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Governor

VERIFICATION OF ENERGYNET® METHODOLOGY

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

December 2010
CEC-500-2010-021

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Acknowledgements

It is important to recognize and thank those who participated in the preparation of this report, by their direct involvement or work on earlier documents and referenced sections that were incorporated in the final report, or in their contributions to the direction and success of the project itself. The list of contributors includes Paul McCabe, Andy Garcia, Allen Thiel, Chuck Pike, Art Hasagawa, Erik Takayesu, Steve Teran, Jeff Shiles, Frank Gonzales, Scott Lacey, Mike Kohler, Son Vo, Mike Tuper, and Ishtiac Chisti of Southern California Edison; and Soorya Kuloor and Rich Hammond of GRIDiant Corporation.

This project benefitted from the following individuals who served as the project's internal technical advisory committee and provided guidance in a variety of ways:

Linda Kelly and Rachel MacDonald (California Energy Commission)

Mike Montoya (Southern California Edison)

Russ Neal (Southern California Edison)

Stephanie Hamilton (Southern California Edison)

Tom Dossey (Southern California Edison)

Rudy Perez (Southern California Edison)

Charlie Vartanian (Southern California Edison)

This project also benefitted from an external technical advisory committee composed of the following individuals:

Bill Torre, Brad Bentley, and Jim Corlett (San Diego Gas & Electric)

Luther Dow and Ken Lau (Pacific Gas and Electric)

It is also important to recognize that demonstration of this methodology had its beginnings in discussions with the Energy Commission's Public Interest Energy Research (PIER) personnel in late 2001, and PIER funding beginning in 2003, both long before distributed energy as a grid resource and the "smart grid" began to receive mainstream attention. The author would like to thank the Energy Commission for its support and PIER funding of this methodology and the vision and foresight evident in those decisions.

Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

Buildings End-Use Energy Efficiency

Energy Innovations Small Grants

Energy-Related Environmental Research

Energy Systems Integration

Environmentally Preferred Advanced Generation

Industrial/Agricultural/Water End-Use Energy Efficiency

Renewable Energy Technologies

Transportation

Verification of Energynet® Methodology is the final report for the Verification of Energynet® Methodology project (Contract Number 500-04-008) conducted by New Power Technologies. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

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Abstract

This report provides the results of a project funded by the California Energy Commission, performed by New Power Technologies, and hosted by Southern California Edison. This report documents the full-scale demonstration and validation of the Energynet® electric power system modeling methodology developed by New Power Technologies in a large utility system. Distributed energy resources are defined as generation, storage, and load control technologies located close to where electricity is used (for example, a home or business) to provide an alternative to, or an enhancement of, the traditional electric power system. Distributed energy resource projects in the right locations and with the right characteristics and operating profiles can improve the performance of an electric power system by reducing power losses, improving reliability and power quality, and increasing load-serving capability. The benefits of individual distributed energy resources can vary significantly depending on location, but can be objectively and rigorously determined using the electric power system modeling methodology tools as demonstrated in this research. These methods, which include various applications of GRIDfast™ optimization software, can also be used to assess the direct impacts and benefits of operational measures such as revised control settings or layout and traditional capital improvement projects. The direct benefits of such diverse system improvement measures can be objectively compared in economic terms.

The key feature of the Energynet® methodology is the simulation of the power system in full detail, with all distribution and transmission equipment integrated into a single model, to allow the direct observation of the grid impacts of individual distribution-connected generation and storage.

This project demonstrated Energynet® electric power system modeling methodology developed by New Power Technologies can systematically identify these beneficial distributed energy resource projects and quantify their benefits for California.

Keywords: Distributed energy resources, demand response, storage; economic analysis, Energynet® , load flow analysis, power system optimization, power system simulation, power transmission, distribution, reliability, renewable integration

Please cite this report as follows:

Evans, Peter (New Power Technologies) 2010. *Verification of Energynet® Methodology,* California Energy Commission, PIER Energy Systems Integration Program, CEC-500-2010-021.

Executive Summary

Introduction

Electric power is delivered to customers over regional power delivery networks comprised of high-voltage transmission and lower-voltage distribution. While techniques for modeling and simulation of these networks at the transmission level are well-known, over 90 percent of these networks are in the distribution portion. Power generation at distribution sites, and demand responsive customer loads, as examples, create interactions within the power delivery network that are not fully visible in a transmission –level model.

This project represents the final research stage with successful full-scale demonstration and field verification of the Energynet® power system simulation method, which integrates electric transmission and distribution system components in full detail into a single model. The researchers used data routinely collected by a large utility to produce an Energynet® model simulating the performance and conditions of a large regional power delivery system at the detail of individual distribution system devices.

The importance of such a model is its ability to predict network conditions at individual devices and line segments within a power delivery system where instrumentation may be sparse and costly to deploy. It can also predict the effects of changes within the electrical system such as the closing and opening of distribution switches to reroute power, the use, or dispatching of demand response, or the use of power generation at customer sites. The visibility provided by such a model may be fundamental to effective deployment of "smart" power grid operational practices and resources widely placed within the power system.

In spite of the potential benefits of such highly detailed system models, they must also be practical in light of reasonably available data, the size and complexity of power delivery systems of California's utilities, and the continuous changes within these systems. Such system models must also prove useful to utilities in terms of the insights provided and enhancements to their decision-making.

Purpose

This project was to complete the research and development, and perform a final demonstration of the practicality and capabilities of this method in a large California utility.

This project also demonstrated some specific applications of the method – showing its usefulness to support power delivery system decision making – and validated the simulation model with field data.

Objectives

The four core research goals of the project were to:

- Demonstrate the practical application of the Energynet® method in a large, complex power system at a California utility.
- Demonstrate the capabilities of the methodology beyond ideal distributed energy resource placement.
- Demonstrate the practical value of the methodology for users to enhance power delivery network decision-making and solve problems.
- Validate the methodology's characterization of an electric power system with field measurement.

The results presented in this report meet these objectives.

The primary subject power delivery system for this project is Southern California Edison's largest regional power delivery system, the "Hobby" system[1]. The Hobby system is large and diverse, serving approximately 280,000 customers, covering about 1,000 square miles, and comprising local transmission, substations, and approximately 241 distribution feeders or circuits, all served from the high-voltage transmission system covering the western United States. For this power delivery system, the researchers produced 15 different Energynet® system models, each characterizing the distribution system with full component detail and fully integrated with the local, regional, and interstate transmission system in a single model.

The researchers generated these models from a variety of conventional data sources provided by the host utility in their native formats with no prior processing by the utility. All but a few interim cases simulate the regional power system's actual conditions on a particular date and time. The researchers also completed models of a second Southern California Edison regional power system and a portion of a third system. Both of the full system models developed for this project were more than 100 times larger than the models developed for the earlier proof-of-concept study

The researchers used these models to assess conditions at individual points within the regional power delivery system, identifying areas with high and low voltage, line segments heavily loaded relative to their ratings, and individual circuits within the system that are unusually vulnerable to random equipment outages.

The researchers used these simulation models to assess the direct impacts of a variety of potential network performance improvement measures, including:

- Operational measures such as changing settings on transformers, dispatching of capacitors, dispatching demand response resources, and other operational changes.

1. This is a fictitious name given to the network.

- “Portfolios” of potential network resource additions including adding capacitors, demand response, generation at customer sites, and adding more distributed storage.

- Substation and circuit expansion projects presently planned for the regional power system.

The researchers continued with the use of GRIDiant Corporation’s’ GRIDfast™ power system optimization and analysis software to identify those operational measures and network resource additions that would provide the greatest voltage and loss benefits by meeting real (active) and reactive resource deficiencies at individual points in the system.

Using results from these simulations, the researchers demonstrated a side-by-side engineering evaluation with a benefit-cost evaluation adapted from a Navigant Consulting, Inc. methodology to provide a rigorous, data-driven comparison of different network performance improvement measures.

To complement and provide verification of simulation model results, a wide-area integrated sensor network was developed on Southern California Edison’s Hobby system. Monitoring included legacy system sensors and, where there were monitoring gaps, new GridSense LineTracker current sensing instrumentation and voltage sensors were installed. The researchers used field data from these sensors to verify the simulation model as a statistically valid predictor of field conditions. The variation of simulated voltage from field voltage at widely dispersed points in the subject system averaged 1.5%, well within the acceptable ± 5% operational voltage variation range.

Conclusions

The results presented here indicate the following conclusions:

- The Energynet® simulation model is a valid predictor of power delivery system conditions at the regional power system level and at the level of individual distribution devices and line segments.

- A regional power delivery system simulation model providing distribution device-level detail is practical even for a large, complex, real-world power system. Further, the potential size of the model, the absence of a perfect, complete, single data source, and the need to update the model frequently for system changes are not barriers to such a high-definition power system model.

- This simulation model predicts conditions within a power system at the circuit level and within circuits at individual devices. It enables identification of changes or additions to the electrical system that will yield the largest benefits, and provides quantified comparisons of these changes and additions.

- The value provided by changes or additions to the electrical system can be quantified in economic terms using a comprehensive set of benefit categories. This type of assessment can be used for a rigorous benefit-cost assessment of these initiatives and to helps compare the merits of dissimilar measures.

This project's demonstration of the practicality of the Energynet® power system simulation in a real-world regional power delivery system and the validation of the simulation model highlights the many applications of the Energynet® methodology. These include:

- Input into a regional power system "state estimator" based on continuous Energynet® simulation updates and real time field data streams.
- Analysis for creating strategies for distributed storage deployments.
- Provide analysis for the evaluation and implementation of conservation voltage reduction.
- Identification of possible sites for renewable power generation projects having low impacts on the regional power system.

There is the desired ability to accommodate high penetrations of intermittent distributed generation as well as distributed storage and plug-in vehicles into the grid. A practical, validated power system simulation tool with system-wide scope and distribution element-level detail, enabling the application of advanced grid analytics such as were used in this project, should readily permit California's utilities to accommodate these distributed energy resources while reducing risk to the power system and unnecessary cost burdens on customers. With the commercial availability of Energynet® electric power system modeling methodology developed by New Power Technologies, and advanced analytic software such as GRIDfast™, California utilities have another tool they can use to help determine the best placement of distributed energy resources.

1.0 Introduction

1.1. Background and Overview

The distinguishing or novel features of the Energynet® power system simulation method include:

- Characterization, simulation, and analysis of transmission and distribution (T&D) as a single, integrated power delivery system, Energynet® system model.
- Consideration of dispatchable customer demand response (DR), customer site or embedded power generation, storage, capacitors and the like (distributed energy resources, or DER) together as available measures to improve power delivery system performance.
- Evaluation of network performance using a broad set of measures.
- Development of an "optimal portfolio" of hypothetical DER projects that illustrate the potential for improvement in network performance from DER and the attributes of DER projects that achieve that improvement.

This method is intended to address the basic problem of objectively assessing the local and systemwide impacts of network performance enhancement measures deployed within the distribution system, including but not limited to DER.

This approach offers the potential to assess power delivery network performance at a level of detail that is 2 to 3 orders of magnitude greater than conventional practice. This project refers to this as "high definition" power system simulation. The systemwide scope and element level detail support objective, data-driven assessment of questions of key interest such as whether, how and where DER can benefit grid performance, and how non-wires and operational measures can be evaluated on an apples-to-apples basis alongside traditional network capital expansion projects.

As a feasibility or proof-of-concept demonstration, PIER Contract 500-01-039 (the SVP Project) used as a subject system a relatively compact, unstressed municipal system, Silicon Valley Power (SVP), and the investigative portion of the project was limited to distributed resources. With the basic feasibility of the Energynet® method demonstrated in the SVP Project, the researchers sought to show that the Energynet® system model was a practical tool for major utilities in California, that this approach could be extended to useful studies beyond DER placement, and that the analytical results could be validated in the field. Of particular interest to the Energy Commission was a demonstration of this method's ability to more fully incorporate non-wires solutions in utilities' system planning.

The Energy Commission believed demonstrations of large-utility feasibility and usefulness of this method, along with field verification, were necessary steps between the proof-of-concept demonstration in the SVP Project and any possible adoption of the method.

In this project the researchers continued with the use of GRIDiant Corporation's' GRIDfast™ power system optimization and analysis software. GRIDfast™ provides an analytical solution to objectively evaluating the merits of thousands or tens of thousands of potential alternative distributed measures through the direct calculation of real (active) and reactive resource deficiencies at every point in a power system. In this project the researchers also built on a benefits model developed by Navigant Consulting Inc. that quantifies in economic terms for multiple stakeholders a wide range of potential benefits of network performance enhancement measures.

Southern California Edison (SCE), a major investor-owned utility in California, served as host to this project, providing data on their power delivery system and the regional transmission system, reviewing infill approaches, reviewing results for reasonableness, and providing input on the implications of the work.

1.2. Project Goals and Objectives

The research goals of PIER Project 500-04-008 as stated in the Contract include the following:

- Demonstrate the methodology as applied previously, but in a larger power delivery system, and using source data typical of one of California's large utilities.
- Demonstrate additional capabilities of the methodology beyond idealized DER placement.
- Demonstrate the practical value of the methodology for users; specifically, the methodology's ability to enhance power delivery network decision-making and problem solving.
- Validate the methodology's characterization of a subject system as an integrated network with field measurements.

The contract states that this project meets or exceeds all of the following PIER Program goals:

- Improving the reliability/quality of California's electricity system by developing an analytical tool that can identify where DER and other non-wire alternatives can be located to help alleviate power quality and transmission and distribution (T&D) capacity and congestion problems in the state.
- Providing more choices to California consumers by helping overcome the barriers to the deployment of distributed generation.

Per the Contract, this project would also aid the transfer of PIER-funded technology into practical use by refining methods for large utility implementation and demonstrating the practical benefits of these approaches to users.

The technical and economic performance objectives of this project include the following:

- Demonstrate the methodology as applied under PIER Contract 500-01-039 to quantify the potential for increased network efficiency and improved performance from ideally situated DER and to characterize the specific attributes of DER projects that achieve these benefits, but in this case demonstrate the method as applied in a larger power delivery system, and demonstrate the use of source data typical of large California utilities.

- Demonstrate capabilities of the methodology and the use of GRIDfast™ beyond idealized DER placement, through the following network analyses:
  - Evaluate the potential network benefits of (or optimize) distribution-level topology reconfigurations.
  - Determine the potential network benefits of switchable or automated distribution devices (e.g., remotely operable switches and capacitors), particularly under varying load conditions.
  - Assess reliability improvement as a network benefit by evaluating proposed measures for their potential to reduce the impacts of known contingencies and investigating operating and optimization constraints that reduce the impacts of known contingencies.
- Demonstrate the methodology's practical value to users and decision-makers:
  - Develop an expanded set of potential measures available to achieve pre-defined operational or functional objectives for the network that includes both wires and non-wires measures, with a direct basis for comparison.
  - Augment the benefits of existing features and planned initiatives, such as existing embedded power generation and demand side initiatives or other DER devices, by identifying additional benefits of power delivery network performance improvement.
- Complete a screening-level assessment of the permitting requirements and potential barriers to new and previously identified projects.
- Demonstrate the methodology's ability to enhance a complete cost/benefit analysis of network options by including an expanded set of measures and an expanded set of benefits through the following:
  - Value the benefits as well as costs of an expanded set of network measures, taking into account the value of network benefits, reliability enhancement, and capital and operations and maintenance (O&M) cost reduction or deferral.
  - Develop a prioritization of network measures.
  - Propose business models for capturing full value of network measures, taking into account technical, policy, and business factors and viewpoints of different stakeholders.
- Validate the methodology's characterization of a subject system as an integrated network, the assumptions and extrapolations used to avoid disclosure of customer-specific meter data, and predicted impact of incremental DER additions and topology changes, with field measurements.

1.3. Report Organization

The rationale for this project and its goals are set out in the Introduction. The Approach and Outcomes are developed in the following threads:

- Model Development

This thread examines the practicality of the Energynet® method as applied in a larger power delivery system typical of California's utilities.

- Network Performance Improvement

This thread examines demonstration in this project of the use of the Energynet® method to identify and evaluate various measures to improve network performance. The topics within this thread directly address the project research goals of demonstrating the capabilities of the methodology beyond idealized DER placement and demonstrating the practical value of the methodology for users and enhancing power delivery network decision-making and problem solving. Topics in this thread also address the project performance objectives of including topology reconfiguration, distribution automation, and reliability improvement as a quantifiable measure of network performance. This thread also addresses the project research goal of demonstrating the methodology's practical value to users and decision-makers and the performance objectives of developing an expanded set of network measures to achieve pre-defined operational objectives and identifying additional benefits of power delivery network performance improvement. This thread explicitly includes traditional network expansion measures alongside non-wires measures such as distributed resources and operational measures such as topology optimization and ideal control settings.

- Ranking/Cost-Benefit Analysis

This thread illustrates the side-by-side comparison of an expanded set of network performance improvement measures from the previous thread. The topics within this thread directly address the project research goal of demonstrating the practical value of the methodology for users and enhancing power delivery network decision-making and problem solving. The topics within this thread also directly address the project performance objective of demonstrating the methodology's ability to enhance a complete cost/benefit analysis of network options by valuing the benefits and costs of an expanded set of network measures taking into account a broad set of benefit categories. It also includes a discussion of business models to capture the full value of network measures.

- Network Monitoring

This thread explores the development and use within this project of a large-scale wide-area power system monitoring system combining existing and new instrumentation, fully integrated with the Energynet® system model, leveraging communication and data management systems.

- Operational and Planning Applications

This thread explores the adaptation of the Energynet® model and related tools and approaches to support operational and planning applications.

- Verification of Methodology

This thread explores the verification of the Energynet® simulation with field data. This thread directly addresses the project research goal of validating the methodology's characterization of the subject system as an integrated system with field measurements. The topics within this thread also directly address the project performance objective of validating the methodology's characterization of the subject system, with its assumptions and extrapolations used to avoid disclosure of customer meter data, and the predicted impact of incremental DER additions and topology changes, with field data.

The subsection numbering of these threads is intended to permit the reader to follow one of these threads without reading this entire report.

2.0 Approach

2.1. Model Development

One of the project's stated research goals is to demonstrate the Energynet® method as applied previously, but in a larger power delivery system and using source data typical of one of California's utilities. Thus, a key feature of this project was the deployment of the Energynet® method in a larger, more complex power delivery system — specifically to demonstrate its practicality in such an environment. Within this context, the researchers would again address the questions of whether the necessary data exists and are in a form and quality that they can be used to develop high-definition models practically.

During discussions with Southern California Edison (SCE) beginning prior to the initiation of the project, the researchers identified the Hobby system as the subject system for this study. At the time, the researchers anticipated that the Hobby model would be about 10 times the size of the model that the researchers had developed in the SVP project, and that it would be developed using essentially the same approach as in the prior project.

2.1.1. "2005" Model

The first purpose of the models that the researchers will refer to as the "2005" models was to demonstrate the availability of data to develop an Energynet® simulation of the subject system and explore the practical challenges of producing such a model in the real world of a large utility. Per the contract scope of work, the researchers would develop a single system model and populate it with actual archived load data from hand-picked dates and times to capture the range of operating conditions the system might encounter in a year.

Identifying a larger, more complex, ideally more stressed "subject system" for this project was fundamental to the project's objectives. During discussions with SCE prior to the start of the project, the researchers identified two areas of the SCE system that were of interest. The first of these, the Hobby system, was identified as a large, fast-growing area with existing or upcoming service needs. A second system, Mountain, was also identified as having growth, though not as rapid as the Hobby system. The Mountain system is also somewhat smaller than the Hobby system, but with more complex topology and more existing generation. All of the SCE place and system names used in this report are substituted names.

Hobby is served by a single 500 kilovolt (kV) feed, and includes two 230 kV local transmission loops, Hobby North and Hobby South.

An Energynet® system model requires device-level detail on all load-serving devices, generators, reactive power sources, switches, and transformers, as well as line segment detail on all lines, in the distribution system and in the transmission system. One research question for this project was whether this information for a large system existed in a useful form within the utility, or could be created using reasonable assumptions.

Working with SCE, the researchers identified key potential data sources. These included the distribution circuit mapping system used by the company, inventories of and interconnection records for distribution-connected and customer-owned power generating units, substation single-line drawings, and customer account databases. For regional transmission outside the Hobby system, the researchers used transmission datasets produced by the Western Electricity Coordinating Council (WECC).

The alignment and features of the Hobby system change from time to time as circuits are added, equipment is retired, and load is redistributed. The researchers agreed that for purposes of this study the project would use a snapshot of the Hobby system as it stood as of mid-November, 2005 for all of the "2005" cases.

SCE's system data archives include current reads and magnetic variation (Mega Volt-ampere reactive, or MVAR) reads for most circuits, as well as substation voltage reads. The supervisory control and data acquisition (SCADA) system also archives device status indications for "automated" capacitors in the system. These were important distinctions in this project as circuit MVAR and capacitor status were not part of the records available in the Silicon Valley Power (SVP) project; in that project the researchers had identified circuit MVAR as a key piece of information that would enhance the Energynet® model's load component.

SCE identified the following days as sample days for the study and provided daily SCADA archive data for these days:

- Super-peak: July 21, 2005
- Normal Summer Peak: August 5, 2005
- Winter Peak: January 4, 2005
- Minimum Load: January 23, 2005

In the SVP Project, the Energynet® dataset comprised about 850 SVP buses. About 37 buses represented SVP's local transmission, which SVP had previously modeled; the rest of the buses, characterizing about half of SVP's distribution circuits, represented newly modeled dataset elements. These elements were integrated into a west-wide transmission model for the Energynet® dataset. The new model data characterizing the distribution elements of the SVP model increased the size and detail of the system model by about 23 times. These added data were developed largely by hand, using takeoffs from engineering drawings and circuit maps.

In early discussions on this project, the researchers estimated that the distribution portion of the Hobby system that would be newly modeled would comprise about 9,000 buses, or about 10 times the size of the SVP system model. However, once the researchers began to extract device and line characteristics from SCE's data for a sample circuit, it became evident that this projection would not hold. It appeared that the first circuit alone would comprise over 1,000 buses, and even if the remaining 200-odd circuits of the system were shorter and less complex, the distribution portion of the model might have 90,000 to 100,000 buses, or an increase in size and detail of over 11 times the budget, all of which would be characterized with newly developed model data.

The researchers agreed with the Energy Commission contact manager in that the hand approach to dataset building the researchers had used for the SVP project would be impractical, and the "investigation" of software extraction, transformation, and loading (ETL) of distribution detail data called out in the contract scope of work became the primary or sole method for dataset building for this project. At the outset the researchers judged internally that the software ETL approach would need to perform all infill to complete for any missing data, and for a system this size would need to yield line and bus results that are 99.9 percent correct or better for the remaining hand work to be reasonably practical.

A related concern was whether the researchers would be able to use available power flow and analytic tools with datasets this large. The researchers confirmed by using dummy data that GRIDiant Corporation's GRIDfast™ optimizer would function with datasets this large. Separately, GE Energy developed for the projects' use an enhanced version of their Positive Sequence Load Flow (PSLF) power flow software capable of using datasets with up to 150,000 buses.

Using software algorithms and scripts automating the methods used in the SVP project, the researchers extracted the needed characteristics of all of the devices and lines of the Hobby distribution system from the sources described above. Other than the single-line diagrams, most of the data sources were machine readable or could be made to be machine readable.

The researchers also used software algorithms to process the SCADA archive data to determine megawatt (MW) and MVAR loads for each circuit as well as line and station capacitor operation and distribution-connected generator operation.

2.1.2. Model Updates

In light of the unexpected scale of the initial "2005" model, the ability to generate new models and to update models within a reasonable time and with reasonable effort emerged as a primary consideration in the demonstration of "practicality" of these models established in the project's research goals. With the agreement of the Energy Commission contract manager, the researchers had focused attention on the Hobby system model. However, to make a demonstration relative to the time and effort that would be required to produce such a model going forward, the researchers developed an Energynet® system model of the Mountain system, which has comparable scale, using 2005-vintage system data in hand, as well as an update of the Hobby system model using system data as of late 2007. The time required to produce these models was of such interest to both SCE and the Energy Commission contract manager that the Mountain system model was actually produced under a timed test with an agreed-upon starting point.

The method for acquisition of SCADA data evolved in the development of a subsequent "2008" update of the Hobby model. Initially the data files that the project received had been produced from data extracted from the archive by hand, with considerable effort on the part of SCE engineers. Partly acting on experience from the demonstration by the Consortium for Electric Reliability Technology Solutions (CERTS) of a data integration, archival, and presentation platform that presented curtailment results also based on SCE load data[2], the researchers sought to more closely integrate this data source by using data reports generated using the archive's internal features.

2.1.3. "2009" Model

The purpose of the so-called "2009" models was initially to provide models reflecting the Hobby system in its current conditions (rather than on specific backcast dates) for comparison with field data drawn simultaneously for the verification portion of this project. The "2009" models were to be developed based on conditions as they occurred rather than for specific types of operating conditions. In addition, one of the objectives incorporated in the authorization for the field demonstration was to investigate whether the Energynet® simulation could be used to support operational decision-making. This would ideally include relatively frequent updates of the system data in the model to capture the ever-changing nature of these systems when considered at this level of detail.

To perform the 2009 Hobby system update, the researchers used the same data sources described above, with new data from SCE characterizing the Hobby system, and new data reflecting Hobby system loads and device status. This project did not obtain updated data for distribution-connected, customer-owned generation, as the projects included in the model are over 25 kilowatts (kW), and the researchers assumed there were few changes in this inventory that would substantially affect the model results.

The source of load data and device status data would be the same as previously, SCE's SCADA archives. However, rather than selecting individual days, the researchers would use data for multiple days for use with the updated model.

Based on prior updates, the researchers viewed the most dynamic data sources for the Hobby Energynet® model to be the system details themselves, which are updated with every change in the "normal" physical layout of the system, and data from the SCADA system and distribution monitoring devices, which the researchers knew would change constantly. Thus the approach to these updates would include some method to at least partially automate the receipt of data from these sources.

A related consideration was how to deliver the results of the Energynet® processing of these data to users other than the project team, a potential technology transfer consideration. A third consideration was security of the source data both before and after processing. All of the source data are SCE proprietary, and some are subject to Critical Energy Infrastructure Information (CEII) non-disclosure agreements as well.

Based on all of these considerations, the researchers committed to an entirely Web-based infrastructure for both the receipt of data from SCE and the management of data within the Energynet® model, using secure Web services to move data between its sources and where it

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2. CERTS May 2007 Demand Response Spinning Reserve Demonstration, LBNL-62761

would be used. The researchers believed this would provide greater security, reliability, and scalability than a local site, even one at SCE, and would support data update streams of any frequency.

The 2009 models were also based on a complete integration of SCE's SCADA data archive system with the Energynet® model, with data from the source fed, in its native from and format, directly to the Energynet® model.

2.1.4. 2011 Forecast Model

The researchers developed a "forecast" model for use in assessing planned conventional network expansion projects as well as DER additions and other network performance improvement measures within the context of expected future loading and system stress.

A forecast model does not need to reflect the frequently changing nature of a more present time power system simulation. Accordingly, the researchers developed the forecast model as an extrapolation of one of the "2009" models. The researchers developed system loads to mimic the substation-level loads forecast for Hobby by SCE, but also retaining the circuit and device-level characteristics of the 2009 model in terms of load distribution and load power factor variability.

2.2. Network Performance Improvement

In Section 2.2 the researchers summarize how they assessed as-found network performance, how they defined and quantified network performance improvement, and what network performance improvement measures they evaluated.

2.2.1. Initial Assessment

A power flow solution of the high-definition Energynet® model under each set of operating conditions provides information on the voltage at each node and the power flow at each line segment under those conditions. The researchers used the results of power flow solution to assess the initial or "as found" condition of the Hobby system under each of the different load conditions this project modeled. Among other things, this "initial assessment" provides a baseline against which to measure the impact of network improvement measures.

For the 2005 Hobby system the researchers simulated the system under five different load conditions intended to reflect the range of operating conditions the system might encounter over the course of a year. These simulations were based on actual loads and actual device conditions taken from SCADA records for the following dates and times:

- Normal Summer Peak: August 5, 2005, Hour 1600
- Super-peak: July 21, 2005, Hour 1400
- Winter Peak: January 4, 2005, Hour 1800
- Minimum Load: January 23, 2005, Hour 0300
- Off Peak: July 21, 2005, Hour 0400

For the 2011 Hobby system, the researchers simulated the system with forecast loads derived from SCE's capital plan for the Hobby system. These loads are described in the capital plan as "normal summer peak" loads. The researchers did not have the benefit of separate forecasts for winter peak or off-peak conditions. The researchers also did not have the benefit of actual device status values to coincide with these loads.

For the 2009 Hobby system the researchers simulated the system using a variety of load conditions.

The initial assessment yields power flow results and supports an evaluation of individual system nodes or buses having voltage outside the desired range and individual line segments and equipment loaded at levels that exceed their ratings.

Because of the detail of the Energynet® model, these voltage, loading, and loss assessments are possible at the sub-circuit level, in fact, down to the individual distribution device and line segment.

2.2.2. Reliability Assessment

One of the performance goals of this project was to introduce reliability improvement as a quantifiable indicator of network performance improvement. Accordingly, the researchers incorporated the "base" reliability assessment of the subject system in terms of outage risk or "expected" unserved energy in kilowatt-hours per year (kWh/yr) as a part of the initial assessment.

As the Energynet® model is populated with pertinent engineering information such as the ratings of individual devices and line segments and the types of switches, whether manual, remotely operable, or automatic, this permits researchers to assess differences in the levels of loading on each component and circuit under different operating conditions through the year. The Energynet® model is also "aware" of the intercircuit connection possibilities of the entire system. So the simulation can support analyses that require knowledge of the circuit details as well as the details and connectivity to adjacent circuits. The Energynet® model is also populated with customer transformer-level loads within the distribution system under a variety of conditions. This enables immediate evaluation of the loading of every circuit element, circuit, and substation in the system relative to each one's normal and emergency ratings at the time of a contingency occurring under super-peak, peak, or off-peak conditions.

Thus, the researchers are able to evaluate loading of individual elements such as transformer banks or line segments relative to their normal and emergency ratings under a variety of operating conditions, using data derived from actual loads under those conditions and power flow results that determine loading at every individual point within the system. The researchers can also use the Energynet® model's topological features to evaluate the alternate feeds available for each circuit for post-contingency load redistribution, and particularly, the backup capacity available on those alternate feeds and whether such redistribution can be done automatically or remotely.

The researchers considered two contingencies to evaluate the baseline reliability of the system: a) an outage of the largest transformer bank in a distribution substation and b) a single distribution circuit line outage that would affect the entire load (every customer) served by the circuit. The researchers considered these contingencies to be random events, with equal probability in all parts of the system and at all times during the year, subject to the following factors:

1. The project treated the probability of a circuit line contingency as increased with longer circuit length.
2. The project treated the probability of a transformer bank contingency as 1/20th the total of the circuit line contingency probabilities for circuits served by the substation.

It is worth noting that this approach has the effect of greater assumed transformer bank outage probability for substations serving longer circuits or more circuits.

The researchers did not explicitly consider transformer bank loading in the basic contingency probabilities. Navigant Consulting, Inc. (NCI) has postulated that circuits loaded at greater than an "upper normal" rating have an increased outage probability.[3] The U.S. Department of Energy (U.S. DOE) has argued that the more equipment operates near its rated capacity, the greater the likelihood of failure.[4] Accordingly, for circuits with individual segments loaded at over 120 percent of their normal ratings, the researchers increased the probability of a circuit line contingency under the operating conditions of the overload by a factor of 10 percent. Combining all of these factors, each circuit had a characteristic "base" contingency rate in terms of hours per year depending on its length and loading.

The researchers then used the Energynet® simulation to evaluate the subject system to assess the impacts of these contingencies in terms of outages, or actual unserved energy to customers – that is, where contingencies result in actual service interruptions. The researchers assumed the following in doing so:

1. In the event of a line outage, a portion of the circuit load would be shifted to one or more interconnected "sibling" circuits to avoid or reduce the duration of unserved load, provided the destination circuit had sufficient capability to serve the additional load. The researchers further assumed that a circuit loaded at 65% or less of its emergency rating was available to pick up a share of the load of an adjacent circuit under contingency conditions.
2. An automatic or remotely implemented circuit load shift would avoid unserved load, while a manual load shift would reduce by half the duration of the interruption.

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3. Navigant Consulting, Inc. October 2008. *Value of Distributed Energy Resources In Distribution Infrastructure, Phase II – Operational Assessment*, U.S. DOE

4. U.S. Department of Energy. June 2007. *The Potential Benefits of Distributed Generation and Rate-related Issues That May Impede Its Expansion*; A Study Pursuant to Section 1817 of the Energy Policy Act of 2005, U.S. Department of Energy.

3. In the event of a transformer bank outage, remaining bank(s), if available, could be operated at up to their emergency ratings to avoid unserved load. Implicit in this assumption is that in the case of substations with split operating buses, in-or near-substation switching would be implemented to move circuits to energized substation buses to avoid unserved load.
4. If a multiple-bank substation has insufficient reserve capacity to continue to serve its circuits under a transformer bank contingency, load representing 1/5th of the served circuits would be shifted to interconnected "sibling" circuits outside the substation to avoid unserved load, provided the destination circuit(s) have sufficient capability to serve the additional load. Again, the researchers assumed a circuit loaded at 65 % of its emergency rating or less is available to accept shifted load from a sibling circuit. For the transformer bank contingency the researchers assumed three destination circuits would be required to move the equivalent load of one circuit.

These are in some ways simplistic assumptions. For example, any contingency requiring a load shift would likely result in a customer outage of some duration. The researchers hoped for reasonable values for the frequency and duration of service outages associated with given contingencies, but not to precisely quantify the frequency and duration of every interruption. With respect to load shifts under transformer bank contingency conditions, the researchers acknowledge that, according to Willis, contingency planning to shift load between circuits served from different substations is an unusual policy given the risks of make-before-break connections across potentially differing voltages.[5]

The project's objective was to bring to light those contingencies having a greater likelihood of causing extended service interruptions based on a systematic evaluation of the inherent features of the subject system, and by inference, bring to light specific areas within the subject system most vulnerable extended interruptions and those features of the system contributing to these differences.

Under this approach the researchers viewed the key determinants of reliability as the availability of multiple transformer banks and their emergency ratings relative to loading, the available capacity and loading of "sibling" circuits, and the type of switching between circuits. Circuit length and circuit loading are also factors. Again, as these factors (other than length) are time and load dependent, the researchers evaluated them under each set of operating conditions. This allowed the researchers to determine for each circuit a characteristic "expected" interruption rate in circuit-hours per year, dependent upon its loading relative to equipment ratings as it varies through the year, its construction, system topology, available reserve transformer and line capacity, and the presence of automated or remote switching.

The Energynet® model is also populated with detail on the number and size of individual customers served at each point on each circuit. Therefore, the researchers were also able to express each circuit's "expected" interruption rate in terms of unserved energy in kWh/yr. This

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5. H. Lee Willis. 2004. *Power Distribution Planning Reference Book* CRC Press, New York.

permits direct identification of circuits having both high interruption risk and heavy loads. This also permits a direct assessment of the type of customers affected and their individual and total loads appropriate for the conditions when the outage is presumed to occur. This supports a “value of service” (VOS) type of analysis to express expected outage rates in terms of dollars per year of unserved energy.

2.2.3. Network Performance Improvement Metrics and Benefit Categories

The characterization of power network performance improvement in objective, quantifiable, and ideally economic terms directly attributable to network performance improvement measures is fundamental to the approach of this project. Section 2.2.3 summarizes how the researchers defined and quantified network performance improvement. Section 2.3 summarizes how the researchers valued observed network performance improvement in economic terms.

Within this study, the researchers considered network performance improvement from several different standpoints. First, the Energynet® simulation permits the authors to directly assess the impact of a given network performance improvement measure in engineering terms using simple “with and without” studies. Some of the network performance improvement measures the researchers had considered were evaluated based on their ability to bring the system closer to an “optimized” state, where this optimization is explicitly directed by a stated objective. The researchers also considered whether a given network performance improvement measure could address identified operational or planning objectives for the subject system. The researchers were also able to assess the impact of network performance improvement measures in terms of specific “benefit categories” shown to provide economic value to one or more stakeholders; this type of analysis supported the economic assessment portion of the project.

Engineering Measures of Network Performance

The primary technical indicators of network performance used in this study are:

- Change in systemwide real and reactive losses.
- Voltage impacts (generally impact on systemwide minimum voltage, also number of buses with voltage under 0.95 per unit (PU), number of circuits containing buses with voltage under 0.95 PU, etc.).
- Reliability impacts (generally the change in expected unserved energy as described in Section 2.2.2).
- Loading impacts (e.g. the change in the number of circuits with lines or elements loaded at greater than their normal rating).

The researchers can also readily evaluate individual network performance enhancement measures for their capacity in megawatts (MW) and energy output in megawatt-hours per year (MWh/yr).

Conventional power flow results permit the authors to determine changes to a modeled system in terms of real (P) and reactive (Q) losses, voltage, and equipment or line loading relative to normal or emergency ratings.

The researchers used the change in systemwide minimum voltage as a proxy indictor for a general improvement in voltage profile. If a given network measure designed to reduce voltage deviation from nominal systemwide has an appreciable voltage benefit at the system's "worst" voltage location, it arguably has beneficial voltage impacts in other less extreme locations. However, changes to the systemwide average voltage or voltage evaluated over 100,000 or more individual points may be invisible given the large numbers.

The reliability assessment the researchers performed, described above, allows the authors to determine the change to a modeled system due to a given measure in terms of unserved energy. This is a quantifiable measure of reliability impacts introduced to the methodology in this project, addressing one of the project's objectives.

Objective Function for Optimization

One of the projects primary tools for identifying performance-enhancing measures beyond power flow modeling was GRIDiant Corporation's GRIDfast™ ™ optimization technology for power systems.

GRIDfast™ is an implementation of GRIDiant Corporation's QuixFlow™ non-linear network analysis and optimization algorithm for electric power networks. According to GRIDiant, QuixFlow directly employs inequality and non-linear constraints, rather than approximating them as linear constraints or equality constraints. Thus it can accurately evaluate, distinguish among, and rank resources for their benefit in a feasible system – that is, one where all constraints are met. Through this capability, QuixFlow can calculate the sensitivity of the entire network, in terms of magnitude and direction of movement toward or away from system constraints or optimization objectives, to a change of a resource at any point.

GRIDfast™ determines and reports "resource sensitivity indices" (RSI) that describe the net impact of incremental (or decremental) resources at each point in the subject network in terms of performance relative to an objective function. As implemented in this project, the RSIs (sometimes referred to as P-Index and Q-Index) indicate either: a) the net benefit, relative to a stated optimization objective, of incremental real (P) or reactive (Q) capacity at that location, or b) the extent to which the absence of real or reactive capacity at that location is adverse to the objective. In this report the researchers refer to real and reactive power RSIs as P-Index and Q-Index interchangeably.

In a system such as Hobby, with thousands of control variables and tens of thousands of potential locations for resource additions, RSIs calculated using GRIDfast™ provide a systematic, repeatable way to select from among a large number of resource addition alternatives.

Using GRIDfast™ , the user can choose multiple simultaneous objectives that can be weighted. In this project, the researchers used as the objective simultaneously minimizing P (real power) losses, Q (reactive power) consumption, and voltage deviation from nominal among the buses and lines that make up the subject system. This objective places equal weight on each of these three elements. However, because P and Q loss reduction also reinforces voltage profile improvement, voltage deviation is effectively the dominant element. This is the same objective as was used in the SVP project. In addition, except as noted, this objective does not directly incorporate flow or loading. Therefore, overload reduction within this objective is an indirect result, as loaded lines cause greater losses and voltage drop, but not a direct result.

RSIs can also be thought of as measuring system "stress." In other words, the real power RSI, or "P Index" or the extent to which the addition of incremental active power resource at a particular point would move the entire system closer to the objective of minimized losses and voltage deviation, is arguably a measure of the "P stress" at that point, and likewise for the reactive power RSI. Changes to these indices were used as one measure of performance in the SVP Project. In this case, the researchers found these indices to be strong indicators of measures that would yield benefits in terms of voltage and losses, but volatile and indistinct direct measures of those benefits.

Reduction in voltage deviation from nominal at every point in a system is a worthy objective that begs the question of how to determine if the voltage profile across an entire power system is really "better." In particular, changes in average voltage or even the standard deviation of all voltages arising from individual system changes are very difficult to see in a set of 110,000 points. Moreover, the researchers judged the correction of voltage extremes to be of greater value. Therefore, the voltage measure this project used most often was the change in voltage at the lowest-voltage point in the system, or systemwide minimum voltage.

Hobby System Operational Objectives

The researchers defined operational or planning objectives for the Hobby system through three approaches. First, the researchers inferred needs from the descriptions and impacts of specific projects included in SCE's capital plan for the Hobby system. Second, the researchers simulated the Hobby system with 2011 forecast loads, but with no physical changes from the present. This simulation revealed overloads and voltage deviations that would arise with these forecast loads and that would presumably be addressed through network performance enhancement measures. Third, the researchers performed a reliability assessment of the 2011 system using the project's reliability methodology. This assessment revealed those circuits having the greatest theoretical risk of unserved energy under forecast loads due to the combined effects of equipment and line loading, reserve capacity, and topology.

Based on these approaches the researchers identified the following specific operational or planning objectives for the Hobby system. Again, one of several metrics used to assess potential network performance measures was their ability to address one or more of these objectives.

The SCE capital plan for the Hobby system and the Energynet® simulation of the Hobby system with 2011 forecast loads identify a need for load relief at the following substations, excluding those whose capacity deficiency would be resolved through a planned load shift.

- Oyster 12 kV
- Fish 12 kV
- Limpet P.T.
- Bobwhite P.T.

- Preventer 33/12 kV
- Boat 115/12 kV
- Sail 115/33 kV
- Hawser 33/12 kV
- Music 115/12 kV
- Paint 115/12 kV
- Author 12 kV
- Bird 115/33 kV
- Heron 12 kV

Incremental effective capacity at the following additional substations sufficient to permit them to operate through a loss-of-bank contingency would improve the theoretical reliability of circuits with the greatest reliability risk as shown by the reliability analysis:

- Wildcat 12 kV
- Tree 12 kV
- Fruit 12 kV

The SCE capital plan for the Hobby system and the 2011 forecast Energynet® simulation identify low voltage and a need for voltage improvement in the following systems, excluding the systems whose low voltage was not confirmed in the simulation.

- Sail 33 kV
- Fruit 12 kV
- Horse 12 kV
- Wildcat 33 kV
- Modjazz 33 kV
- Bird 33 kV

The SCE capital plan for the Hobby system also identifies a need for load redistribution on circuits served from the following substations:

- Macaw
- Metal
- Boat
- Modjazz
- Weckl

The SCE capital plan for the Hobby system and the researchers' reliability analysis using the 2011 forecast model of the Hobby system indicate the need for enhancement of post-contingency load shift opportunities for circuits in the following systems:

- Shellfish
- Tree
- Bird
- Modjazz
- Sail
- Heron
- Fruit
- Garden
- Flower
- Wildcat
- Music

Network Performance Benefit Categories

In parallel with this study, Navigant Consulting, Inc. (NCI) developed a benefits model in a study funded by the U.S. DOE's National Energy Technology Laboratory[6] to derive and value benefits of DER that applies a common set methods and assumptions across DER measures and technologies. The NCI benefits model extends across several types of benefits and takes into account multiple affected stakeholders, to more comprehensively assess the full benefits of dissimilar network performance enhancement measures. This model includes a set of "benefit categories" that support economic quantification of the impacts of network performance enhancement measures from the standpoint of a variety of stakeholders.

In their study, NCI demonstrated the benefits model as applied to the DER projects of the 2005 Optimal DER Portfolio for the Hobby system developed by the researchers and discussed in Section 3.2.6.

The researchers adapted this benefits model for use in evaluating potential performance enhancement measures in economic terms in this project. The researchers' implementation of the NCI benefits model included the following ten benefit categories:

- Reliability
- Power Quality
- Conservation Voltage Reduction Potential
- Bulk System Capacity
- Ancillary Services Capacity
- System Voltage Security

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6. Navigant Consulting. October 2008. *Value of Distributed Energy Resources in Distribution Infrastructure; Phase II—Operational Assessment*," Final Report, National Energy Technology Laboratory RDS Contract DE-AC26-04NT41817

- Energy in the load center (and congestion-relief)
- Loss Reductions
- Emission Reductions
- Load Relief

Reliability impact as a quantifiable measure of network performance improvement is added in this study, addressing one of the performance objectives of the study. Power Quality and Conservation Voltage Reduction are indicators demonstrated by NCI that place economic value on the voltage impacts of network measures. Bulk System Capacity, Ancillary Services Capacity, and System Voltage Security are all related to the capacity value of network measures. Load Relief is related to transmission and distribution (T&D) capital deferral but is, the researchers feel, a more objective measure of a network performance enhancement measure's ability to address constraints that might otherwise necessitate capital expansion projects.

The NCI benefits model assesses benefits from the standpoint of multiple stakeholders. Table 1 below, adapted from the NCI study, shows each of the ten benefit categories used by the researchers in this project by stakeholder. Utility (U) refers to the utility or network operator. Utility benefits are financial benefits that accrue directly to the utility. Utility/Ratepayer (U/R) refers to benefits that accrue initially to the utility but ultimately to all customers of the utility in the form of reduced costs. Customer (C) benefits accrue directly to the customers of the utility. Strictly speaking these benefits, reliability and power quality, would accrue only to the customers within the subject system. Societal (S) benefits accrue to society at large and are not confined to the subject system.

Table 1: Benefit categories by stakeholder

Benefit Category	U	U/R	C	S
Reliability		X	X	
Power Quality			X	
CVR		X		
Bulk System Capacity		X		
Ancillary Services Capacity		X		
System Voltage Security		X		
Energy		X		
Loss Reductions		X		
Emissions Reductions				X
Load Relief	X			

Source: NCI

Under the NCI benefits model, each benefit category has economic value to one or more stakeholders. Accordingly, the network performance enhancement provided by a given measure, can be valued in economic terms based on its impact in each of these benefit categories.

The researchers have incorporated the NCI work in this project's results at the direction of the Commission contract manager. Developing these results in coordination with the NCI study presented an opportunity to align the analysis of this project with a spending prioritization and benefits model approach already in use by California utilities and also to adapt that approach to more fully incorporate DER as a potential network enhancement measure.

The following is a more general discussion of network performance effects and benefits ascribed to various network measures in the NCI study and several other studies. To ensure that network effects are truly benefits that are objective, quantifiable, and directly attributable to given network measures, in some cases NCI's approach or the researchers' approach required different or more concise benefit definitions. Section 2.3 discusses the economic valuation the researchers applied to each benefit category in the benefit-cost evaluation of network performance enhancement measures.

Reliability

Network performance enhancement measures are often characterized as "improving system reliability" in a general or qualitative way. One of the stated performance objectives of this project was to assess reliability improvement as a quantifiable network benefit that could be rigorously attributed to particular network performance enhancement measures.

To evaluate the impact of a given network performance improvement measure on the system's reliability relative to the baseline reliability discussed above, the researchers judged that a given measure (such as DER) could impact reliability in three specific ways by reducing loading on particular parts of the system. First, reduced load on a key circuit might make that circuit available to receive shifted load from a "sibling" circuit under either a transformer bank or line contingency in an instance where customer load would otherwise be dropped. Second, reduced load within a substation's circuits might allow that substation to operate through a loss-of-bank contingency rather than curtailing loads, where opportunities to shift load outside the substation are limited. Third, enough load reduction on certain loaded circuits might reduce their assumed failure probability.

The researchers evaluated reliability impacts in terms of the change in the expected annual unserved energy due to essentially random contingencies, taking into account the cumulative effects of topology and reserve capacity on each individual circuit in the system.

The researchers considered load reductions that eliminate expected normal-condition overloads as a separate benefit, discussed under "Load Relief."

In its study, NCI performed a separate analysis of the reliability of the Hobby system and the reliability impacts of the 2005 Optimal DER Portfolio projects presented in Section 3.2.6. NCI defined reliability benefits as a reduction in sustained outages and outage impact. In evaluating the potential reliability benefits of the 2005 Optimal DER Portfolio projects, NCI posited that DER capacity within a power delivery system could reduce peak feeder overloads, thereby reducing feeder outage probabilities, and enhance post-contingency restoration by reducing switching operations, both yielding improvements in system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI). This characterization of the sources of specific reliability benefits is similar to that used in this project's approach.

The key differences between the NCI reliability analysis and the researchers' own are that the researchers' reliability assessment evaluates individual line segments for their loading relative to their rating, individual circuits for their post-contingency load transfer opportunities, and individual substations for their ability to either operate through transformer bank outages or lay off load via circuit-level load shifts. This project's approach also incorporates the total reliability risk on circuits served from distribution circuit-served substations including parent circuit risk. This approach enables a rigorous assessment of each circuit's reliability risk individually. This level of granularity is consequential – the researchers' findings show very dramatically that the cumulative effect of these factors results in vastly different reliability risks from circuit to circuit. Another key difference lies in terms of loads – the researchers' assessment was based on actual loading at a given date and time so all of the conditions are coincident.

Other authorities corroborate the view that reduced system loading from DER can improve reliability, though apparently without any specific reference to enhancing post-contingency load shift opportunities, which the researchers found to be the largest component of reliability benefits when quantified. The U.S. DOE states in its June 2007 "1817 report to Congress" on DER benefits[7], that DER can indirectly improve reliability by reducing the number of times during the year when distribution equipment is used "near nameplate ratings" reducing the frequency of equipment failures.

In its assessment of California's Small Generation Incentive Program (SGIP)[8], TIAX LLC identified reliability benefits from distributed generation projects as "likely very high" for project participants, non-participants, and society, but did not attempt to quantify or price these benefits.

In the 1817 report to Congress, the U.S. DOE also states that DER can directly affect power delivery system reliability by reducing the line distance between sources and loads. In other words, the combined outage rates and durations of a substation and many line sections may be greater than the outage rates and durations of a distributed generation (DG) unit. The researchers did not explicitly take this consideration into account; however, the researchers' reliability analysis results in Section 3.2.2 show clearly that line distance is a significant factor in the theoretical reliability risk of a given location within a power system as the researchers defined it.

The U.S. DOE also states that DER can directly affect reliability of the host customer by serving as a backup supply. The researchers did not take this consideration into account, primarily because the interconnection agreements of grid-tied distributed generation under California's Rule 21 would generally prohibit the unit's operation during power delivery network outages.

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7. U.S. Department of Energy. February 2007. *The Potential Benefits of Distributed Generation and Rate-related Issues That May Impede Its Expansion.* A Study Pursuant to Section 1817 of the Energy Policy Act of 2005.

8. TIAX LLC. October 2008. *Cost-Benefit Analysis of the Self-Generation Incentive Program.* Prepared for the California Energy Commission, CEC-300-2008-010-F.

The U.S. DOE also states that DER can affect reliability by diversifying and spreading supply resources. The researchers did not explicitly take this factor into account, either.

Voltage Support

Voltage support is a benefit attributed to various network improvement measures. In this study, the researchers evaluate essentially every network performance enhancement measure in terms of voltage "impacts." However, the researchers purposefully draw a distinction between impacts and benefits and attempted to consider voltage impacts in the context of identifiable, quantifiable, and ideally valuable benefits.

In the SVP Project, the researchers had identified as a benefit "voltage profile improvement" – specifically, an increase in system average voltage, elimination of low- and high-voltage buses, and reducing voltage variability (standard deviation) or deviation from nominal voltage. Voltage profile improvement in that study was not valued in dollar terms but was characterized therein as presumably reducing O&M, improving power quality, and permitting conservation voltage reduction.

In the June 2007 1817 report to Congress, the U.S. DOE defined as a service "voltage support" or "maintaining line voltage within the accepted nominal range." The U.S. DOE states that reactive resources provide this service, including by distributed generation with Volt-ampere reactive (VAR) production capability in the right locations and with the proper grid operator controls. The researchers' studies show that DER providing real power can also have benefits in terms of maintaining voltage within the desired nominal range.

Energy and Environmental Economics, Inc. (E3), in its long-term avoided cost methodology[9] for estimating benefits of DER[10], likewise defines "voltage support" as an ancillary service, provided by generating units or other equipment such as shunt capacitors, static VAR compensators, or synchronous generators, which is required to maintain established grid voltage criteria." E3 states that such services are procured through long-term contracts.

NCI points out in its study that quantification of the value of voltage support from the utility stakeholder perspective presents challenges, and NCI did not place a value on "voltage

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9. Energy and Environmental Economics, Inc. October 2004. Methodology and Forecast of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs. Prepared for the California Public Utilities Commission Energy Division, available at http://www.ethree.com/CPUC/E3_avoided_costs_Final.pdf

10. The E3 methodology is nominally intended for energy efficiency programs. E3 states its methodology is most appropriate for evaluating resources that; a) reduce load or produce energy for hundreds of hours per year in a predictable pattern, b) are relatively small (such that they can be installed behind the customer meter), and c) are expected to be installed in large numbers.

support” as a service consistent with the definitions above. NCI’s benefits model instead disaggregates “voltage” impacts in terms of i) specific power quality improvements (and related impacts on interruptions of customer processes), ii) the impact on the potential for conservation voltage reduction, and iii) T&D operations and maintenance (O&M) cost savings due to less voltage variability. Each of these is discussed below.

In this study the researchers followed NCI’s approach, disaggregating voltage impacts of network performance measures into other specific benefits; neither the researchers nor NCI treated “voltage support” as a standalone service or benefit.

Power Quality

In its benefits model, NCI defines the benefit “power quality” as a reduction in dynamic voltage swings, particularly where such swings could result in interruptions of customer processes. DER (or presumably other measures) that could reduce the occurrence of such events by reducing voltage sag was ascribed a power quality benefit. This benefit would accrue to customers. Reduction in such power quality (PQ) events that interrupt customer processes are one of three benefits NCI ascribed to the voltage impacts of DER.

In the June 2007 1817 report to Congress, the U.S. DOE concurs that distributed generation can support local voltage levels and avoid an outage or meaningful PQ event that would otherwise have occurred due to excessive voltage sag. The U.S. DOE also states that power quality problems are local, not systemwide, and most are cost-effectively dealt with locally. This is consistent with the view that DER can yield these specific power quality benefits.

In this study the researchers essentially adopted NCI’s definition of power quality as the frequency occurrence of voltage swings that could result in interruptions of customer processes.

Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) refers to the practice by the network operator of reducing customer delivery voltage, thereby reducing consumed and generated electrical energy (MWh). In its benefits model, NCI refers to CVR as an “energy efficiency” benefit category. To the extent that DER (or any other measure) improves voltage profiles to allow delivery voltages to be reduced while remaining within specifications, NCI would ascribe an energy efficiency benefit. The benefit, in the form of energy not generated, yields a cost savings that ultimately accrues to ratepayers.

Enabling CVR is one of the benefits NCI ascribed to the voltage impacts of DER. CVR is related to voltage in that it can only be implemented where voltage profiles are sufficiently flat to allow a voltage reduction while keeping the lowest voltages above minimum voltage specifications. In this study the researchers adopted this approach but refer to the benefit as CVR rather than energy efficiency.

Transmission and Distribution Operations and Maintenance Cost Savings

NCI posited that a reduction in the range of steady-state voltage sags that occur within the subject system can reduce Operations and Maintenance (O&M) costs through reduced maintenance or preventative maintenance of voltage regulation equipment. To the extent that DER or other measures improve the voltage profile of circuits and reduce the voltage variability at a given location, NCI would ascribe an O&M cost savings benefit. (NCI also postulates that improved reliability yields O&M savings in terms of reduced crew expenses, but that benefit is captured in the quantification of reliability benefits.) Reductions in steady-state voltage sags were one of the benefits NCI ascribed to the voltage impact of DER.

E3, in its valuation methodology, indicate that there is a transmission and distribution (T&D) O&M cost savings benefit to reduced energy use in the delivery system, as distinct from any T&D O&M cost savings from reduced voltage sags. In the case of the E3 methodology, this T&D O&M benefit is included in the T&D adder.

NCI found the potential value of such savings was very small compared to other benefit categories, and the researchers do not include it in this project as a benefit category.

Bulk System Capacity

In its benefits model, NCI posits that DER capacity can defer investments in traditional electric generation *capacity*, yielding a cost benefit that ultimately accrues to ratepayers.

In the June 2007 1817 report to Congress, the U.S. DOE introduces the concept of "Reduced Peak Power Requirements" as a "service" (rather than a benefit), providing a variety of benefits. The U.S. DOE states that reduced peak power requirements can displace costly alternatives and reduce wear and tear on delivery equipment, reducing maintenance costs and overall capital investment requirements.

In the researchers' view, utilities (or electrical load-serving entities) must have available a given amount of generation capacity ("bulk system capacity") to deliver energy as needed, accommodate normal demand variation, meet reserve margins, and compensate for the time lag in bringing new resources on line to meet load growth. Further, in California investor-owned utilities have "resource adequacy" requirements to maintain sufficient capacity and must document annually that they have sufficient capacity resources.[11] Accordingly, in this project the researchers treat "capacity" as a standalone commodity or benefit, whose value depends on the conditions under which it is available and the location at which it can be reliably scheduled for delivery. The researchers also see capacity as a permanent benefit, valuable as long as the resource is demonstrably available, and not merely a deferral of some other cost.

In this report the researchers refer to bulk system capacity as a resource providing the ability to deliver energy as needed, etc., as described above, and to meet resource adequacy requirements. Subject to market rules, demand response, distributed generation, and storage can provide such capacity. Strictly speaking, bulk system capacity resources in the Hobby

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11. Woodward, Jim and Marc Pryor. November 2009. *An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California.* California Energy Commission, Electricity Supply Analysis Division. CEC-200-2009-019 available at <http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.pdf>

system would be resources that meet resource adequacy requirements that apply to the Hobby area if they are different than for the bulk power system generally. Ancillary services capacity is a specialized type of capacity, and capacity associated with DER cannot count as both bulk system capacity and ancillary services capacity.

Ancillary Services Capacity

In addition to resource adequacy capacity, utilities or participants in the interconnected grid must provide or maintain specialized capacity, called "ancillary services," having particular operating characteristics such as response within a given time. Resources providing true capacity, such as demand response, distributed generation, and storage, can, at least potentially, provide ancillary services capacity. Such capacity is generally more valuable than resource adequacy capacity; however, a resource generally cannot provide bulk system capacity and ancillary services capacity.

In the June 2007 1817 report to Congress on DER benefits, the U.S. DOE identifies "ancillary services" as a "service" (rather than a benefit), providing a variety of benefits. According to the U.S. DOE, ancillary services include regulation, operating reserves, and voltage support, and distributed generation can provide both voltage support and reserves if the projects are located where these services are needed and offer the appropriate level of network operator control.

In its long-term avoided cost methodology for estimating benefits of DER, E3 ascribes a value to reduced purchases of ancillary services in a "Reliability Adder." E3 proposes relating reduced ancillary services purchases to reduced demand, while acknowledging that other than for spinning reserves and non-spinning operating the relationship between demand and ancillary services needs is not one-to-one.

In its assessment of the SGIP, TIAX identified "avoided ancillary services charges" as one of the higher-value benefits of self-generation and as a benefit accruing to non-participants and, to a lesser extent, to society. TIAX did not propose a method for valuing avoided ancillary services charges.

In its assessment of the 2005 Optimal DER Portfolio projects, NCI assumed that some resources could provide 10-minute operating reserve capacity, 30-minute supplemental reserve capacity, or regulation capacity. (As a matter of nomenclature, this project will interpret "operating reserves" as "non-spinning" reserves and "supplemental reserves" as "replacement reserves."). NCI states that only residential heating, ventilation and air conditioning (HVAC) demand response is suited to serve as operating reserves because the capacity must be available any time, and as consumers would have to opt in, many non-residential customers would decline. NCI assumed that half the residential demand response would provide an operating reserve benefit. NCI states that only storage is suited to serve as regulation, which must be available to adjust positive or negative on a real-time basis.

The Consortium for Electric Reliability Technology Solutions (CERTS) has demonstrated the ability for demand response resources – even legacy HVAC load cycling – to provide spinning reserve capacity on a sustained basis.[12] In the CERTS study, the spinning reserves were assumed to be available within 10 minutes; the study showed the possible response as near-instantaneous. CERTS further demonstrated the ability to target this capacity through circuit-level marketing of demand response and then obtain or dispatch this capacity anywhere it is available in the system, using circuit-level dispatch. CERTS states that institutional practices and market rules would have to evolve to fully utilize this resource. CERTS further demonstrated that demand response resources might be called repeatedly for periods typical of spinning reserve deployments (5 to 20 minutes) without customer complaints. This is an important finding as it suggests that demand response may serve as reasonably durable spinning reserve capacity, and with spinning reserve calls of short enough duration, the dispatch limits on HVAC load cycling demand response may not be a major factor.

CERTS also shows that spinning reserve prices are typically three times higher than non-spinning reserves (and five times higher than replacement reserves) and argues that a resource that is capable of providing spinning reserves should be thus used if possible.

As discussed more fully in Section 2.3.5, in this project the researchers distinguished among types of ancillary services capacity and assumed that different types of resources could provide different forms of ancillary services capacity. Specifically, the researchers assumed that demand response can potentially provide spinning reserves as well as non-spinning operating reserves subject to its availability and market needs, and that storage can potentially provide regulation reserves during peak periods, again subject to the system's needs. The researchers view the real power output of dispatchable distributed generation as generally controlled by the site host or customer, in which case distributed generation has bulk system capacity value, but it would not offer the operational flexibility to serve as spinning, operating, or replacement reserves.

System Voltage Security

NCI defines "energy security" or system voltage security in their benefits model as the avoidance of system voltage collapse. A contingency that causes voltages in a power system to drop below about 70% of nominal (0.70 PU) can cause running HVAC units to "stall," creating a self-reinforcing phenomenon pulling voltages lower until the entire system experiences voltage collapse. Very quick load reductions in sufficient quantities, particularly the disconnection of loads such as HVAC units that might otherwise stall and contribute to the event, can prevent the contingency from propagating and leading to system voltage collapse.

Under this definition, adopted by the researchers in this project, system voltage security as a potential benefit category is a function of the amount of HVAC cycling demand response available in the system. The benefit is unavailable until the demand response reaches a certain high penetration level. This benefit is additive to the other capacity-related benefits, principally ancillary services, attributable to this demand response capacity.

12. CERTS May, 2007 *Demand Response Spinning Reserve Demonstration* LBNL-62761

Energy

Operating DER projects produce electrical energy that is, by definition, at the point of use or in the load center. So this energy potentially has value both in bulk system terms and, if applicable, in terms of avoided congestion or a location premium. In the SVP Project, the researchers did not value energy itself ("bulk energy") from DER as a grid benefit. In that study, the researchers essentially took the position that energy from DER simply displaces energy of equal market value *at that location*.

In the researchers' view, the true incremental benefit of energy from DER is indirect, arising from its change in source (potentially reduced congestion) or form of generation (potentially reduced emissions). In other words, bulk energy and congestion avoidance are in fact separate value streams; this is the approach the researchers took in this project. The bulk energy value of a given network measure may flow to the utility, its non-participating ratepayers, or the participating DER host customer, depending on contractual arrangements. Any congestion avoidance benefit of the measure accrues first to the delivery network operator, then to ratepayers depending on rate treatment, and any emission reduction benefit accrues to society.

In its benefits model NCI does ascribe a value to bulk energy from DER as "energy savings" displacing energy from traditional generation sources. The value of this energy is entirely a ratepayer benefit, assuming true-up mechanisms for any marginal benefits or costs.

E3, in its long-term avoided cost methodology for estimating benefits of DER, also ascribes a value to avoided electricity generation. E3 recommends utility-specific, hourly values based on bulk power trading values, distinguishing different pricing regions as appropriate. E3 also suggests an embedded adder for capacity, using a natural gas combined cycle combustion turbine power plant as a proxy. E3 additionally suggests a "price elasticity of demand" adder to reflect higher overall energy prices that would be associated with avoided higher energy use.

In its assessment of the SGIP, TIAX identified energy commodity savings (energy costs avoided by the utility in not serving the participant), congestion charge savings, and congestion reduction savings as non-participant and society benefits. TIAX suggests that avoided energy costs for distributed generation be derived using facility "clusters" (aggregated on a ZIP code basis) to represent energy commodity savings; energy values can be spatially resolved using locational marginal prices (LMPs), which account for marginal losses and congestion costs.

To perform its retrospective evaluation in the absence of actual LMPs, TIAX used Northern and Southern California daily zonal wholesale market prices, attributed distributed generation projects mapped to each zone by ZIP code.

TIAX states that prospectively, with the availability of LMPs, studies predict wide variations in LMPs as LMPs price in congestion costs and losses. TIAX describes a security-constrained economic dispatch analysis for biennial runs for 2009 through 2017 to determine prospective commodity prices, which found the potential for sustained LMP premiums in some locations of $15 to $20 per MWh.

The TIAX assessment report also states its belief that traded energy prices historically have been lower than the utilities' cost of generation, and that avoided served energy should be valued at the utilities' cost of generation rather than traded energy prices.

Loss Reductions

Nearly every network performance enhancement measure that this project evaluated has some loss impact. Loss reduction is one of the benefit categories in the NCI benefits model, with the benefit accruing to utilities and ultimately to customers as a cost savings.

E3, in its long-term avoided cost methodology for estimating benefits of DER, identifies line loss reduction as a potential benefit of DER. In its assessment of the SGIP, TIAX also identified transmission and distribution loss savings as a potential benefit of distributed generation.

The researchers in this project essentially adopted the NCI model for loss reduction benefits. The Energynet® simulation uniquely permits direct assessment of the loss impacts of network performance enhancement measures in both transmission and distribution over a variety of operating conditions through simulations.

In its benefits model NCI evaluates loss reduction in terms of energy savings and also in terms of reduced peak demand.

Emission Reductions

In its benefits model NCI attributes emission reduction benefits to certain DER resources. Energy and Environmental Economics (E3), in its long-term avoided cost methodology for estimating benefits of DER, also identifies emission reductions as a potential benefit of DER. In its assessment of the SGIP, TIAX also identified emissions reductions as a potential benefit of distributed generation.

The extent of these emission reductions is, of course, a function of the alternative source of energy displaced; in the case of the SGIP program, the distributed generation units are by definition renewable or high-efficiency combined heat and power. In its benefits model, NCI attributes emission reduction benefits to DER as PV generation, demand response, and energy storage.

In this project the researchers attributed emission reduction benefits to the net energy production of PV distributed generation, demand response, and storage, but also to the loss reduction attributed to those resources. The researchers also attributed emission reduction benefits to the loss reduction associated with non-supply measures.

Load Relief/Transmission and Distribution Deferral

Network performance enhancement measures that provide incremental capacity and energy from within the power delivery system, such as DER, can effectively increase the capacity or load-serving capability of the existing power delivery system, *provided* the DER relieves (is electrically linked to) a system constraint that would otherwise limit the load-serving capability of the system. Depending on anticipated growth and capital investment plans, incremental capacity and energy from such DER can defer the need for new capital investments, under the right circumstances and for a period of time. DER additions can also provide VAR support either through incremental capacity or by reducing the system's VAR consumption. Note that here the researchers are referring to a benefit that is distinct from loss reduction, improved reliability, or in-load-center energy.

The California Public Utilities Commission's (CPUC) *Energy Efficiency Policy Manual*[13] for assessing the overall cost-effectiveness of energy efficiency (and, the manual notes, potentially self-generation and demand response) from a societal perspective identifies transmission and distribution costs as costs that are avoided through reductions in energy demand. Avoided transmission and distribution costs are assessed based on a statewide average of weighted forecasts of avoided T&D costs across utility service territories and converted from $/kW to $/kWh to be applied to reduced energy demand using a 0.6 (60%) load factor.

E3, in its long-term avoided cost methodology for estimating benefits, proposes a "T&D Adder" capturing incremental demand-related capital expenditures, line losses, and maintenance costs within individual utilities' planning areas and climate zones otherwise associated with increased energy use. Planned T&D investment deferrals are estimated based on reductions in peak loads and are allocated geographically among temperature-based climate zones coinciding with utilities' T&D planning areas.

In its assessment of the SGIP, TIAX identified "distribution capital deferral savings" as a benefit of distributed generation. The TIAX study also argues that deferring transmission is a theoretical benefit, and as transmission is a small share of customers' total cost of service, deferring transmission is necessarily a small economic opportunity for distributed generation. TIAX recommends assessing individual self-generation units' size and operating profile along with the nameplate and capability ratings and recent peak loadings of the system serving the customer where the units are immediately connected. Any year in which the peak loading of a distribution element is deemed likely to exceed its maximum loading capability, absent the self-generation unit, counts as one year of potential upgrading deferability (that is, without any direct consideration of other measures that may be available to address the overload and without any direct consideration of the peak period availability of the unit). However, in its report TIAX indicates that they encountered many difficulties implementing such a methodology in terms of data availability, documentation, and time.

The CPUC efficiency manual's approach simply attributes a T&D deferral benefit to a demand reduction in any utility's territory. The E3 approach adds a level of locationality by linking demand reductions in a particular climate zone to T&D capacity deferral in that zone, but still stops short of identifying real system constraints or actual mitigation of those constraints by the measures receiving the value attribution. These are really attempts to capture and assess at least a portion of a real grid benefit of DER projects while lacking information on how individual

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13. California Public Utilities Commission. October 2001. *Energy Efficiency Policy Manual, Ver. 1*; Decision 01-11-066 Available at <http://docs.cpuc.ca.gov/published/Final_decision/11474.htm>.

projects affect the system. The TIAX methodology at least supports the idea of evaluating individual self-generation projects for their impact on the system where they are connected; however, their report indicates they were unable to fully implement this approach due to limitations in the availability of data indicating the ability of projects to defer distribution upgrades.

NCI characterizes T&D capacity deferral as providing higher effective distribution/substation capacity and VAR power support, thus deferring planned feeder and substation investments. NCI's analysis was based on specific feeder or substation expansion projects identified in SCE's capital plan for the Hobby system[14]. Under the right circumstances, DER can provide firm capacity that is equivalent to the incremental capacity of the planned network expansion project, therefore arguably deferring the project.

The NCI approach essentially equates the nominal capacity value of a planned network expansion project with a real constraint that will be relieved, and attributes a capacity deferral benefit to DER projects that provide equivalent firm capacity. Through the Optimal DER Portfolio, NCI had the benefit of potential DER resources identified by individual circuit (and affected substation), thus this approach comes closest to a direct impact relationship between DER and a planned T&D capital expenditure that might be deferred.

The limitations with this approach are that network expansion projects are necessarily "chunky" and may provide capacity beyond what is directly needed for relief, and also that there may be real system constraints that are not associated with and/or relieved by identified capital projects.

The researchers' analysis of the Hobby system network expansion projects suggests that there are both real (demonstrated) constraints that are not relieved by planned projects, and that not all planned projects relieve demonstrated constraints. Therefore, the existence of a proposed capital project that might be deferred is not a reliable indicator of true value. In the researchers view, a load relief or capacity deferral value for DER or any other measure is dependent on whether there is: a) a real constraint in the system, or b) that would actually be relieved by the measure. In other words, the constraint that is relieved must be identified, and the measure must be in a location within the system to electrically affect that constraint.

In the SVP project, the researchers evaluated DER additions in terms of "improved load-serving capability." Specifically, the researchers performed simulations of the modeled system with and without DER additions to determine the resulting change in the maximum load that could be served under a contingency involving the loss of the single largest component (N-1) without overload. The advantage of this approach is that it permits an objective comparison between DER projects and network expansion projects. However, this approach is not available for the Hobby system since the system always has nominally overloaded elements.

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14. NCI's analysis was based on the Hobby capital plan as of 2005, whereas network expansion projects evaluated in Section 3.2.8 were taken from the Hobby capital plan as of 2009.

Therefore, the researchers approach in this project for this benefit category departs in a significant way from the entire premise of capital expenditure "deferral." Instead, the researchers approach the topic from the standpoint of "load relief." A measure provides a "load relief benefit" if it relieves a demonstrated overload, irrespective of any T&D capital expenditures that might be planned. This overcomes two limitations of a "capital expenditure deferral" approach – first, that a real or anticipated overload may not have a planned capital project tied to it and second, that a planned capital project may not relieve a real or anticipated overload. Assessing measures for their load relief benefit allows an objective, side-by-side comparison of network expansion and non-wires measures such as DER.

The researchers' simulation of the 2011 Hobby system with forecast loads and no other changes allows us to determine the actual constraints in the system with anticipated loads before any remediation, at least under "normal peak" conditions. The researchers can then make an objective assessment of the load relief that is needed along with the load relief that might come from potential network performance improvement measures.

Valuing "load relief" in economic terms remains somewhat problematic. Where there are network expansion capital projects identified to address a demonstrated constraint that could be deferred, the cost of these projects (or the value of their deferral) is one measure of the value of this load relief. However, the researchers do not have a good way to estimate the value of load relief for which there is no proposed capital project. Also, this assessment arguably must be applied over several years using a multi-year load forecast to determine the duration or durability of this load relief.

While a non-traditional network performance enhancement measure may address an identified overload and/or defer a traditional network expansion project, there may be further potential benefits associated with such a project. First, the project may avoid the cost of overinvesting for an expected constraint that ultimately does not materialize. Second, while a load relief capital project may provide a block of effective incremental capacity, a constraint may be intermittent, and may be adequately addressed by an intermittent alternative measure such as demand response. There is, arguably, inherently greater value in flexible solutions that could be brought on incrementally, as needed, in light of uncertain future system demands. The researchers did not directly incorporate these considerations into this analysis.

Thus, the researchers did not include "T&D investment deferral" as a benefit category. All measures instead were evaluated in terms of their "load relief", or, specifically, their ability to relieve real constraints identified through system simulations.

2.2.4. Recontrols

GRIDfast™ can be set to re-dispatch all existing resources and available operational controls to an "optimum" configuration relative to the stated objective, or in this implementation, that feasible configuration that minimizes voltage deviation from nominal, P losses, and Q consumption. The researchers refer to this measure as "recontrol" or ideal control settings. Based on discussions with SCE, the researchers specified available controls and resources in the Hobby system as:

- All station capacitors (52 total in the 2005 system)
- All line capacitors (787 total)
- All transformer tap changers under load TCULs (89 banks total)
- All line voltage regulators (14 total)
- Reactive power output of all existing embedded generators with Q capability (13 units of 26 total)

For purposes of this study the researchers considered even the transformers with fixed taps as having variable sending-side voltages. The researchers also considered all capacitors identified in the system data as operational. Taken together, these represent 955 total controllable variable resources in the 2005 Hobby system, widely dispersed within the Hobby system.

Because GRIDfast™ considers the impact of each element on the entire system, recontrols as applied here mimic a systemwide, centrally controlled system for dispatching these resources.

For each operating case, the researchers determined the changes in control variables from the "as-found" condition to bring the system performance closest to the objective, and the impact of the recontrol steps on P and Q losses.

For the 2011 forecast case, the researchers have no reliable way of knowing the capacitor and transformer tap settings in the "as found" condition, so this project was unable to directly simulate the standalone impact of recontrols.

Distribution Automation – Capacitors and Distributed Generation

Expanded remote or automated control of devices within a power delivery network is both desirable and costly. In this study, the researchers evaluated the use of the Energynet® model as a tool to identify those individual devices that would yield the greatest benefits in terms of network performance through their inclusion in a distribution automation scheme.

Recontrol results for the 2005 Hobby system presented in this report include simulations of the Hobby system with capacitor settings manipulated using GRIDfast™ to bring the system to its optimal operating condition relative to the stated objective under a variety of operating conditions. Also, because the capacitors are dispatched according to the GRIDfast™ optimization under each set of conditions, the approach used here is illustrative of a single central capacitor dispatch scheme driven by a particular optimization function to maximize performance systemwide.

The researchers used these results to extract an operating profile for each of the system's capacitors over the range of operating conditions encountered during a year. The researchers' thesis is that capacitors whose operating status should change frequently to maintain high-performance system conditions are more valuable candidates for automation, while automation of capacitors whose status never or rarely changes is arguably less valuable.

Of the existing distribution-connected generating units in the Hobby system, this project modeled 13 as having synchronous generators, and the capability to produce or consume reactive power within normal generator limits. As stated above, the researchers considered these resources available as "recontrol" elements. As with conventional line capacitors, to the extent that these generation-based VAR resources would end up actively used under varying operating conditions, there is arguably value in incorporating them in a control scheme with remote dispatch.

2.2.5. Redispatch of Existing DER

The Hobby system has a substantial number of existing DER resources, primarily demand response, but also a variety of distributed generation units. One of the "network measures" this project evaluated was the potential for improved network performance through redispatch of these resources. As noted above, the reactive output of the existing synchronous generators was included as an available resource for recontrol.

In a process similar to that described below for DER additions, the researchers used GRIDfast™ to evaluate and rank the impact of each resource relative to the objective function. This allowed us to identify those resources that would yield the most benefits in terms of loss reduction or voltage profile improvement if dispatched on a coordinated basis.

Distribution Automation – Enhanced Existing Demand Response Automation

As discussed in Section 3, the researchers found that some existing demand response resources in the Hobby system, when dispatched correctly, are valuable system resources in addition to means to reduce energy consumption under high load conditions. Among the over 4,600 existing demand response projects in the system, the researchers identified 125 resources that alone would increase systemwide minimum voltage under super-peak conditions by 0.4% and reduce the number of low-voltage buses by 67. The researchers also identified a second tier of an additional 875 more demand response resources that would measurably increase the systemwide minimum voltage and further reduce the number of low-voltage buses. Accordingly, the evaluation of these individual projects also indicates where to obtain the most value through demand response automation – automated, condition-based, individual, remote dispatch of demand response and possibly closer monitoring for performance.

2.2.6. Optimal DER Portfolio Additions

The Optimal DER Portfolio is an idealized set of hypothetical DER additions (capacitors, demand response, distributed generation, and distributed storage) that would achieve the greatest share of potential network performance improvement available from DER. This is not a set of projects to implement, necessarily, but a set of projects against which to evaluate real projects. More importantly, fully defining these projects in terms of their location, size, type, and operating profile illuminates the ways the subject system can be improved by DER and the particular attributes of DER projects that will yield those benefits.

DER Capacity Addition Electrical Characteristics

As the Optimal DER Portfolio is a set of hypothetical projects, with guidance from the Energy Commission and SCE, the researchers established a set of generic characteristics that are representative of each class of DER resources, even if not necessarily representative of every individual project. The researchers also assume any communication systems and rate provisions needed to deploy these units as described are in place.

Demand Response

For purposes of this study, the researchers considered as "demand response" dispatchable demand response only. By this, the researchers mean load that can be reliably reduced on demand in response to a signal or order from the system operator, and thus is reasonably considered a system resource. Accordingly, demand response as used here does not include energy efficiency measures, which are not reductions on demand, or voluntary measures, which are not reliable load reductions.

Electrically, the researchers considered demand response resources as consisting of both active or real power (P) and reactive power (Q) in proportion to the power factor of the load that is reduced.

Distributed Generation

The researchers considered distributed power generation to consist of inverter-based generators, inductive generators, or synchronous generators. One of the criticisms of the SVP Project was that the researchers did not directly consider the use of inverter- and inductive-based generators in small distributed generation applications, as these generator types have different VAR capability, and thus different impacts, than synchronous generators. The researchers therefore address that concern here.

The researchers assumed inverter-based generator systems would operate at a fixed, unity power factor; that is, they have only real power capability and no reactive power or voltage regulating capability. The researchers assumed inductive generator-based systems would introduce reactive load at a fixed rate of 0.5 Kilo volt-ampere reactive (kVAR) per kW of active power output. This is taken from the typical PQ characteristics of an uncompensated wind farm, which consumes approximately 0.5 MVAR per MW produced. While not all small inductive generators meet this power factor specification, some will be partially compensated, and the researchers feel this is representative of the group. The researchers assumed synchronous generators were capable of independently dispatchable reactive supply or load ranging from positive 0.5 kVAR to negative 0.33 kVAR per kW.

Storage

This project considered "storage capacity" to be sources of real (active) power that can be sustained over a peak load period – that is, for several hours. Storage capacity as considered in this study was also assumed to have citing flexibility to allow the researchers to evaluate its value as a system resource comprehensively. Accordingly, for purposes of this study, "storage" is not seasonal, it is not pure ride-through, and it is not necessarily pumped storage. Sample technologies for storage projects as the researchers consider them here include flow batteries, zinc bromide batteries, and, in over-1,000 kW sizes, sodium sulfide batteries.

As defined in this project, storage capacity must also represent an active power load at the same location during a corresponding off-peak period. This requires a two-case optimization, as the optimization must consider both the impact of storage capacity available at each location during peak periods and the impact of storage load at that location during off-peak periods. The researchers also assumed storage capacity would consume power during recharge at a rate of 1.25 kW per kW of output (discharge) capability. Due to the need for the second, off-peak case, the researchers did not develop a storage component for the 2011 Hobby system Optimal DER Portfolio. Implied in this assumption is that storage at least for this project's purpose is not mobile within a daily period.

The researchers assumed storage capacity also represents a variable source of reactive power. Vanadium Redox VRB flow batteries offer active VAR compensation. The researchers assumed storage capacity represents plus/minus 1 kVAR of independently variable, sustained-output reactive capacity per kW of active capacity.

DER Capacity Addition Limits

With guidance from SCE and the Energy Commission, the researchers imposed certain limits and constraints on DER additions. These limits are intended to reflect both the realistic high-side potential of these resources and to incorporate prudent operational constraints on their penetration in the case of distributed generation.

These limits reflect both the characteristics of the customer served at each site, and the characteristics of the system at that point. Using information supplied by SCE, the researchers populated the Energynet® model with the rate schedule and customer "class" of the customer(s) served at each of the roughly 45,000 load-serving transformers in the Hobby system. As described below, the researchers used this information to derive device or bus-level DER limits.

Demand Response

As stated above, for purposes of this study, the researchers considered as demand response load that could be reliably reduced on demand in response to a signal or order from the system operator. A factor, therefore, in setting realistic limits on dispatchable demand response is the availability and cost of controls and communication to effect on-demand load reductions.

The researchers considered all customer sites that are "residential" based on their rate schedule as potential or candidate sites for HVAC cycling. The researchers characterized these demand response projects as representing 25% of the peak load at that location, and available only during super-peak periods. Such customers would in general have essentially no metering, communication, and on-site device controls to support other demand response projects.

This project considered all "small business" customer sites (less than 20 kW demand based on rate schedule) as potential or candidate sites for HVAC cycling as well. In the case of these customers the researchers characterized this as representing 15% of the peak load at the site and again available only during super-peak periods.

This project considered all medium business, large business and industrial, and some agricultural and pumping customers as potential or candidate sites for demand response, with exceptions noted below. The researchers assumed medium business, large business and industrial, and some agricultural and pumping customers would likely have more sophisticated metering, communication, and on-site energy management capability. Thus, for these customers demand reductions would not necessarily be limited to HVAC cycling. Accordingly, the researchers assumed these customers would be capable of providing dispatchable demand response for system purposes during periods other than super-peak periods, though at lesser levels. The researchers also assumed a portion of customers in these classes would be capable of greater levels of demand reduction under some circumstances.

This project considered all "medium business" (between 20 kW and 500 kW demand based on rate schedule) and agricultural and pumping customer sites capable of dispatchable demand reductions of 2% of their peak load during either super-peak conditions or during periods other than super-peak. The researchers further assumed that 20% of these customers were capable of higher levels of demand reductions of 15% of their peak load during super-peak conditions.

This project considered all "large business and industrial" customer sites (greater than 500 kW by rate schedule) capable of dispatchable demand reductions of 6% of their peak load during super-peak conditions and 2% of their peak load during periods other than super-peak. The researchers further assumed that 60% of these customers were capable of higher levels of demand reductions of 15% of their peak load during super-peak conditions and 5% of their peak load during periods other than super-peak.

SCE has a substantial number of customers with existing dispatchable demand response capability; the researchers modeled 4,732 sites in the 2005 Hobby system with existing demand response capability. The researchers modeled all of this demand response capability discretely; the researchers also assumed these customers were not available for additional demand response projects. The researchers assumed residential HVAC cycling resources to represent a fixed 2 kW increment, and non-residential HVAC cycling and interruptible resources to represent 15% of the customer's peak load; and in all cases, available only during super-peak periods.

Some pumping and agricultural customers have arrangements that prohibit their operation during peak periods. The researchers assumed these customers were not available for demand response projects. The researchers have also assumed specially metered non-highway outdoor lighting loads and traffic signal load sites were not available for demand response projects.

Applying these screens to the 45,916 load-serving sites in the 2005 Hobby system, there are 39,950 sites eligible for demand response additions, but only 3,313 sites eligible for demand response additions during periods other than super-peak conditions. Therefore, under these assumptions demand response as a resource class has far more potential under super-peak conditions. There are also 4,732 discretely modeled existing demand response projects, including 4,391 existing residential and small business HVAC cycling sites and 341 large business interruptible customers.

For the 2011 Hobby system Optimal DER Portfolio, the researchers followed essentially the same approach. However, without the benefit of different cases for different operating conditions the researchers simply assumed all demand response additions were continuously available as capacity but strictly limited in terms of annual hours.

Distributed Generation

This project considered all "residential" customer sites as potential or candidate sites for distributed generation in the form of photovoltaic (PV) projects. The researchers characterized these as inverter-based systems comprising 50% of the peak load at that site. While some individual customers may install PV systems that will both cover their peak load and export, this is representative of the group of customers served from a load-serving transformer. This assumption does not directly take into account 100% PV housing developments, which the researchers see as a special case.

This project considered all "small business" customer sites (less than 20 kW by rate schedule) as potential or candidate sites for distributed generation in the form of PV. The researchers characterized these as inverter-based systems comprising 25% of the customer's peak load.

This project considered all "medium business" customer sites (between 20 kW and 500 kW by rate schedule) as potential or candidate sites for distributed generation up to 60% of the customer's peak load. For customers with peak loads up to 60 kW, the researchers assumed these would be inverter-based PV systems. For customers with peak loads between 60 kW and 200 kW, the researchers assumed these would be inductive generator-based systems. For customers with peak loads over 200 kW, the researchers assumed these would be synchronous generator-based systems.

This project considered all "large business and industrial" customer sites (over 500 kW by rate schedule) as potential or candidate sites for distributed generation up to 60% of the customer's peak load. The researchers assumed these would be synchronous generator-based systems.

The researchers note that in nighttime conditions (i.e., the minimum load and off-peak hour of the peak day cases), many sites are eligible for distributed generation additions in the form of PV, but these projects would not produce power. The researchers further note that for the purposes of this project, customers will not devote the capital to build exporting distributed generation projects (i.e., projects larger than their own peak load).

The researchers assumed specially metered non-highway outdoor lighting loads and traffic signal load sites were not available for distributed generation projects.

Applying these screens, of 45,916 load-serving sites in the 2005 Hobby system, 45,477, or nearly all, are eligible for distributed generation projects.

The researchers also imposed circuit-level penetration limits on distributed generation. One of the criticisms of the SVP Project was that the researchers established circuit-level distributed generation limits to ensure non-export, but did not directly address fault protection or anti-islanding concerns given the absence of specific facilities for unsupervised breaker reclosing and re-synchronization. The researchers address these concerns here.

Large synchronous distributed generation units can contribute to the fault duty of all of the elements on a distribution circuit. This impact is limited here both with the size limit on synchronous generators of 60% of the customer's peak load described above and the circuit limit on synchronous generator penetration described below.

Also, by limiting the size of any distributed generation addition to less than the peak load at that site, by definition the transient from the largest single distributed generation unit trip is less than the transient that would be introduced by the largest single load.

Given a fault or other action causing the accidental separation of a portion of a circuit containing both generation and load, and assuming the absence of transfer trip mechanisms, distributed generation unit(s) could fail to trip or isolate themselves, creating an unintentional island, contrary to recommended utility practices. To address this, the researchers have limited potential additions of synchronous and inductive generation capacity on any circuit to half of the circuit's minimum load plus 20%, again, assuming the absence of transfer trip mechanisms.

This circuit limit is similar to the basis for the Rule 21 Simplified Interconnection limit of 15% of a circuit's peak load – that is, if the circuit's minimum load is 30% of its peak load, and the allowed penetration is to be limited to half of the circuit's minimum load, the resulting limit is 15% of the circuit's peak load. The limit used here is slightly higher as where the circuit limit is reached, the distributed generation units on that circuit will consist of a mix of inductive and synchronous generation.

Because inverter-based generation is typically equipped with active anti-islanding capability, the researchers allowed an additional increment in the circuit limit for inverter-based generation of 15% of the circuit's minimum load.

The researchers note that higher circuit-level distributed generation penetration could be safely accommodated. However, this would require additional study and/or protective measures to address individual project concerns. The limits applied here are in, in the researchers' view representative, of broad penetration, mass-market distributed generation rather than highly customized projects capable of supporting individual project integration studies.

Storage

This project considered all physical buses (structures) eligible for the installation of storage capacity – that is, potential storage sites were not limited to load-serving sites. The researchers set an area-wide "budget" for storage of about 2% of the area's peak load, or 35 MW for the 2005 Hobby system. The researchers did not set any individual bus limits or circuit limits on storage additions.

It is important to note that this project's storage "strategy" of populating a system to about 2% of peak load with storage of unspecified unit sizes was formulated in 2004-2005. More specific storage strategies such as those involving multiple layers of distributed storage[15] and specific purposes such as augmenting intermittent renewable resources within the distribution system[16] have evolved well after the framing of this study. However such strategies could be evaluated, ranked, and valued using this project's approach.

DER Addition Project Identification

This project's primary tool for this portion of the analysis was GRIDiant Corporation's GRIDfast™ optimization technology for power systems. As stated previously, in this instance the researchers used as the objective for optimization simultaneously minimizing P (real power) losses, Q (reactive power) consumption, and voltage deviation from nominal among the buses and lines that make up the Hobby system. This objective places equal weight on each of these three elements. However, because P and Q loss reduction also reinforces voltage profile improvement, voltage deviation is effectively the dominant element. This is the same objective used in the SVP project.

Properly programmed, GRIDfast™ will:

a) Assess the P and Q Indices (real and reactive power stress) of the subject system.
b) Add the P or Q resource at the eligible location where it will yield the greatest benefit relative to the objective – that is, the location with the most extreme P or Q Index.
c) Re-optimize and re-assess the P and Q Indices of the system with the resource just added.

GRIDfast™ repeats this sequence until either all limits are fulfilled or there is no incremental benefit to be gained from the addition of P or Q resources. The result is a set of resource additions rank-ordered in terms of their impact on the system's performance relative to the objective.

While the "initial" P and Q Indices, those assessed before the addition of any resources, are an indication of the locations where incremental resources will yield the most benefit, at least in theory the merits of capacity additions at one location may change following resource additions at another location. Under the process described above, the researchers re-optimized and re-assessed the P and Q Indices following each addition.

For the 2005 Hobby system the researchers identified and modeled pure Q additions (capacitors) first, then demand response additions, distributed generation additions, and finally storage additions. The rationale for this ordering is as follows. The researchers presume the most cost-effective way to address a pure Q deficiency (after recontrols) is with capacitor

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15. B. Roberts. March 2010. *Taking Grid Energy Storage to the Edge*. PowerGrid International, March 2010.

16. M. Rawson. March 2010. *How Can Energy Storage Enhance the Value of PV in a Smart Grid Environment?* DistribuTECH 2010, March 23-25, 2010.

additions. Likewise, demand response is most likely the lowest-cost resource among demand response, distributed generation and storage, followed by distributed generation, then storage.

This is not intended to be a comprehensive cost-benefit ranking among these alternatives. Its purpose is to ensure that benefits that could be achieved through capacitor additions are not ascribed to demand response and that benefits from demand response are not ascribed to distributed generation, a more costly and more difficult-to-acquire resource. Likewise, benefits that could be achieved through demand response and distributed generation should not be ascribed to storage.

This project also assumed existing distributed generation was available and optimally dispatched. As noted above, the researchers considered existing demand response available only under super-peak conditions, and performed a sensitivity to assess the impact of these resources as described below. In other words, benefits that would be achieved with existing DER were not generally ascribed to new DER.

The researchers made assessments in each of the following cases:

- Normal Summer Peak: August 5, 2005, Hour 1600
- Super-peak: July 21, 2005, Hour 1400
- Winter Peak: January 4, 2005, Hour 1800
- Minimum Load: January 23, 2005, Hour 0300
- Off-peak hour of Super-peak Day: July 21, 2005, Hour 0400

The beneficial demand response and distributed generation additions identified under each set of conditions, taken together and assessed from an individual site perspective, imply a set of seasonally adjusted operating parameters for demand response and distributed generation at that site. These with the customer-specific characteristics for these projects result in a specification for each project at each site.

For the 2011 Hobby system the researchers evaluated capacitor additions, demand response additions, and distributed generation additions each against the same starting conditions, the system with optimized controls.

2.2.7. Alternate Topologies

The results of the SVP Project, in particular some studies of that subject system with an all-networked topology, suggested very preliminarily that there might be significant network performance benefits from alternative network topologies. One of the performance objectives of this project is to explore the potential benefits of alternate topologies as a network performance enhancement measure.

The Energynet® model is "aware" of the inter-circuit connection possibilities of the entire modeled system. Using this feature the researchers were able to identify the individual tie switches cross-connecting each circuit. In a radial system model inter-circuit tie switches are all open, and in fact, the researchers completed analyses to confirm that this was the case in all of the subject system models.

As discussed above, GRIDiant Corporation's GRIDfast™ power system optimization analytics provide an index indicating the resource deficiency or surplus relative to the predetermined optimization objective at each point in the system. Thus, the researchers are able to identify for each inter-circuit tie switch the difference in the resource deficiency index across the open switch. The researchers` hypothesis is that those switches separating the greatest difference in resource deficiency would relieve those extremes in resource deficiencies that also happen to be readily accessible by single switch closures and thus yield the greatest network benefit relative to the stated objective if closed.

It is important to note that given two circuits with open cross-ties, if one circuit is highly resource deficient and the other is in resource surplus, all the connections between the circuits will show a large difference in resource deficiency. However, if one connection is made, the resource deficiency across the remaining ties between the two circuits should change dramatically. Therefore, the determination of those switches separating the greatest difference in resource deficiency must be refreshed with every topology change.

Accordingly, the researchers established a process in which GRIDfast™ would:

a) Assess the P Index (real power resource deficiency or "stress") difference across each identified open tie switch in the subject system.
b) Close the tie switch that will yield the greatest benefit relative to the objective – that is, the switch with greatest P Index difference.
c) Re-optimize the system and re-assess the P Index difference across each open tie switch.

GRIDfast™ would repeat this sequence until all switches are closed, all limits are fulfilled, or there is no incremental benefit to be gained from further closures. The result is a set of tie switch closures rank-ordered in terms of their impact on the system's performance relative to the objective.

The researchers studied both networked topology and radial topology reconfiguration. In the case of the latter, implementing a switch closure identified by the GRIDfast™ analysis also requires identifying and opening related sectionalizing switches to ensure that the overall topology remains radial, that there are no new loops, and that there are no new islands. These are discussed separately below. In every case the starting system condition was the same, with the network in an "optimized" condition with respect to capacitor dispatch and transformer tap settings.

It is important to note that under the approach used here the explicit objective is to relieve extreme resource deficiencies (or surpluses) at specific points and thereby reduce system losses and voltage variability, the same objective as was used for optimized control settings and in identification of ideal DER additions. Accordingly, the approach used in this study is not explicitly directed toward other possible objectives such as overload relief. The researchers' purpose here is to demonstrate a systematic approach to optimizing topology, in this case using a previously established objective, and to investigate the impact of "optimized" topology in a manner closely tied to the researchers' evaluations of the other performance enhancing measures that the researchers have investigated.

Networked Topology

The Hobby system operates in a radial topology. Some loop-fed (or circuit-served) substations have dual feeds that can be operated as looped. Apart from those, all load-serving circuits are distinct radials with a single source. Here the researchers sought to assess the potential system performance benefits of networked topology. The researchers' results from the SVP Project suggested that there are considerable theoretical loss and voltage profile benefits from networked topology, and that these benefits may not be evenly distributed among all networking switch closures. If a subset of the available networking switch closures can yield most of the potential benefit of networked topology, such a partially networked topology might be more practical.

Having used the Energynet® model to produce an inventory of all of the inter-circuit tie switches in the Hobby system, the researchers used GRIDfast™ to assess the P Index difference across each open switch, as described above. Consistent with a networked approach, the researchers modeled the highest-ranked tie switch as closed and repeated the process, eventually showing the entire system as fully networked and ranking all available inter-circuit tie switches in terms of their contribution to improved system performance relative to the objective. The researchers repeated this for different operating scenarios to assess the relative importance of each switch in a networked topology under the different operating conditions the system would see during the course of a year.

Optimized Radial Topology

As indicated above, a key methodological difference in determining "optimized" radial topology is the need, for a tie switch closure, to identify a second switch to open. Accordingly, with each closing/opening pair of switch manipulations, a portion of one circuit and block of load is effectively moved from one circuit radial to another. Here, the researchers identified the switch to close as in with networked topology described earlier by the difference in P resource deficiency between the two nodes of the open switch as measured by GRIDfast™ . The researchers found in the course of implementing this method that it is the choice of the second switch of the pair to *open* that establishes several important parameters, including:

- The amount of load included in the shift
- The direction of the shift
- Whether the new configuration creates an island or loop

These factors are not directly visible to the GRIDfast™ analytics or incorporated in its benefit ranking of potential tie switches to close. However, the Energynet® model is topologically aware, and the researchers were able to identify for each proposed switch closure a paired switch to open that would maintain radial topology, not create a loop or island, and move load in the correct direction to relieve, not exacerbate, a real power resource deficiency.

The researchers also found during the course of the study that, depending particularly on the amount of load included in the move, a just-opened switch might actually be identified later by the analytics as the next best choice to close. Further, the latter move might serve to move load back in the opposite direction, reversing the earlier move, or it might serve to move additional load in the same direction, augmenting a prior move. Once this became evident, the researchers adapted an approach to add recently opened switches to the pool of switches available to close.

These load shifts are conceptually similar to load shifts a utility may include as an element in system planning. However, here the load shifts are systematic and purely analytically driven, to relieve real power resource deficiency as measured by GRIDfast™ and move the system closer to optimal pursuant to the stated objective, apart from any other consideration. In addition, by looking at optimized topology under a variety of conditions, the researchers can identify topology changes that would be implemented seasonally or even within the day, between peak and off-peak conditions.

Distribution Automation – Switch Automation

Expanded remote or automated control of devices within a power delivery network is both desirable and costly. In this study, the researchers evaluated the use of the Energynet® model as a tool to identify those individual devices whose automation would yield the greatest benefits in terms of network performance.

The results from the topology optimization described above identify particular individual switches whose manipulation would bring the system closer to its optimal operating condition relative to the stated objective under a variety of operating conditions. Here, the researchers used these results to extract operating profiles for these switches over the range of operating conditions encountered during a year. Switches whose status has a significant impact on system conditions through either networking or load shifting *and* that must be manipulated regularly to maintain those impacts are arguably the most valuable candidates for automation.

The results from the system circuit-level reliability assessment presented elsewhere in this report incorporate the availability (or lack of availability) of automatic or remotely operable switches for post-contingency load shifting. In instances where a circuit's expected interruption risk would be reduced by automation of its tie switches alone, that circuit's switches are the most valuable candidates for automation. These circumstances are distinguished from instances where: a) a circuit already has automated switches available for post-contingency load shifts, and b) a circuit's expected interruption risk is dominated by other factors such as the capability of neighboring circuits to accept additional post-contingency load.

2.2.8. Reliability Optimization

In this portion of the study, the researchers sought to develop and demonstrate a methodology that would use GRIDfast™ and the Energynet® model to show ways to improve system reliability through principally the following means:

- Reduced impacts of given contingencies.
- Enhanced post-fault restoration (reducing outage time).
- Identification of demand response and distributed generation capacity additions with specific benefits in reducing the impacts of given contingencies or enhance post-fault service restoration.

The researchers employed GRIDfast™ differently in this portion of the study, incorporating two specific elements:

- Optimization of system conditions under post-contingency conditions.
- Flow minimization as an objective function, specifically under post-contingency conditions where potential overloads might limit restoration opportunities.

The researchers based these studies on particular transformer bank failure contingencies that would affect large blocks of load. Having identified the affected areas of the system for each contingency and the potential paths (switch closures) for restoration for each, the researchers went through each possible restoration path, evaluating:

- Those switch closures that could achieve restoration within a "feasible" or converged power flow solution.
- Those switch closures that could achieve restoration with the system re-optimized to operate under post-contingency conditions.
- Those switch closures that could achieve restoration without overloading the transformer taking on the additional load.
- Those switch closures that could achieve restoration with the benefit of ideally placed DER resources.

If post-contingency recontrol optimization or DER additions did indeed enable or expand the restoration options, the researchers could conclude that these control changes and DER additions would reduce the impact of the contingencies in question, enhancing reliability.

The researchers conducted elements of this evaluation under summer peak, super-peak, winter peak, and off-peak conditions.

Restoration of these large load blocks affected by a transformer contingency via a single path is an extreme approach both in the sense that it places the most load on the destination infrastructure and in the sense that it involves the smallest number of switching operations. Unless a power delivery system is designed with substantial excess capacity specifically to allow load shifting in large blocks, conventional practice would sectionalize the affected load block and restore service via several paths, as in the multi-zone distribution design approach described by Willis and noted in the discussion on the reliability assessment below. Nonetheless, if through this approach the researchers are able to identify usable single-switch restoration opportunities; these could give operators more choices, for example, where single-switch load shifts could allow service to be restored quickly while a more distributed post-contingency configuration is implemented.

2.2.9. Substation and Circuit Expansion Projects

The SCE capital plan for the Hobby system includes descriptions of specific network expansion projects. These projects generally involve adding substations, upgrading substation equipment, adding or relocating resources (typically reactive power sources), adding circuits, and/or redistributing portions of existing circuits. With additional input from SCE, the researchers were able to incorporate these projects in the 2011 Energynet® model and simulate the local and systemwide impacts of each project on the entire power delivery network's performance.

The researchers also included in this evaluation planned load shifts as described in the Hobby capital plan and substation transformer bank addition projects, but did not model these in the 2011 Hobby simulation.

2.3. Ranking/Benefit-Cost Analysis

In general, this project summarizes results derived from the simulations of the Hobby system in two states. The researchers simulated and evaluated the Hobby system as it stood in 2005, with several cases bracketing the operating conditions likely to occur during the course of a year derived from actual conditions at that time. The researchers also simulated and investigated the Hobby system as forecast in 2011 with projected normal summer peak loads. The former results illuminate the actual behavior of the system and how varying system conditions influence the merits of various performance improvement measures over the course of an operating year. The researchers believe these assessments of network performance measures, using actual conditions from archived data recorded over a variety of seasons, provide important insights that go beyond a pure peak-forecast-only view. Actual data reflecting different conditions show how a power system's behavior changes as operating conditions and loads change during the day and during the year. These data are also free of the assumptions and judgment necessarily involved in preparing a load forecast.

Cases derived from actual conditions, such as backcasts, have limited decision-making value, as they only show the system as it was. The researchers' case simulating the Hobby system with forecast loads is more representative of a typical planning exercise. However, this case incorporates forecast loads and conditions that must be based on assumptions and judgment. More importantly, such a case cannot provide the seasonal and daily variation element of the backcast cases. Accordingly, with a single forecast case, the researchers can obtain rigorous findings from a simulation, but the researchers must then extrapolate these results in a far less rigorous manner to obtain annualized benefits for comparison.

In every case valuation results for benefits are stated in constant dollar terms on an annual ($/year) basis.

As described above, for the 2005 cases the researchers implemented DER in sequence – after recontrols, capacitor additions, existing and new demand response, distributed generation, and storage are each layered onto the prior set of results. The researchers evaluated alternative topologies as a standalone measure relative to the 2005 Hobby system with ideal control settings (recontrols) only. As the researchers evaluated various measures' impact on the 2011 forecast Hobby system, they evaluated each measure relative to recontrols only. Therefore, the researchers can evaluate the alternative topology and 2011 DER addition measures alone, without the impact (or distortion) of other measures.

What the researchers hope to present in these results is an objective comparison of a wide range of potential network enhancement measures on a standalone basis. In reality, network performance enhancement measures would be implemented as part of a plan, in a particular order, ideally with each measure deriving some share of benefits from the others. With a comprehensive assessment of the full benefits of a wide range of measures on an individual basis, that outcome can easily be achieved with a second iteration that was not demonstrated in this report.

2.3.1. Reliability

One of the performance objectives of this project was to assess reliability improvement as a quantifiable network benefit.

To evaluate the impact of a given network performance improvement measure on the system's reliability relative to the baseline reliability discussed above, the researchers judged that a given measure (such as DER) could affect reliability in three specific ways by reducing loading on particular parts of the system. First, reduced load on a key circuit might make that circuit available to receive shifted load from a "sibling" circuit under either a transformer bank or line contingency in an instance where otherwise customer load would be dropped. Second, reduced load within a substation's circuits might allow that substation to operate through a loss-of-bank contingency rather than curtailing loads where opportunities to shift load outside the substation are limited. Third, enough load reduction on certain loaded circuits might reduce their assumed failure probability.

The researchers evaluated reliability impacts in terms of the change in the expected annual unserved energy due to essentially random contingencies, taking into account the cumulative effects of topology and reserve capacity on each individual circuit in the system.

This project considered load reductions that eliminate expected normal-condition overloads as a separate benefit, as discussed under "Load Relief."

In its study, NCI performed a separate analysis of the reliability of the Hobby system and the reliability impacts of the 2005 Optimal DER Portfolio projects. NCI defined reliability benefits as a reduction in sustained outages and outage impact. In evaluating the potential reliability benefits of the 2005 Optimal DER Portfolio projects, NCI posited that DER capacity within a power delivery system could reduce peak feeder overloads, thereby reducing feeder outage probabilities, and enhance post-contingency restoration by reducing switching operations, both yielding improvements in SAIDI and SAIFI. This characterization of the sources of specific reliability benefits is similar to that used in the researchers' approach.

The key differences between the NCI reliability analysis and the researchers' own analysis are that the researchers reliability assessment evaluates individual line segments for their loading relative to their rating, individual circuits for their post-contingency load transfer opportunities, and individual substations for their ability to either operate through transformer bank outages or lay off load via circuit-level load shifts. This projects approach also incorporates the total reliability risk on circuits served from distribution circuit-served substations including parent circuit risk. This approach enables a rigorous assessment of each circuit's reliability risk individually. This level of granularity is consequential – the results in Section 3.2.2 show very dramatically that the cumulative effect of these factors results in vastly different reliability risks from circuit to circuit. Another key difference lies in terms of loads – the researchers' assessment was based on actual loading at a given date and time, so all of the conditions are coincident.

NCI valued reductions in sustained outages in terms of direct customer value using the Value of Service values, as shown in

Table 2. According to NCI, these values were derived based on studies conducted by the California utilities, NCI's own studies, and analyses performed by Lawrence Berkeley National Laboratory (LBNL), among others. This project also used these values (the researchers interpret "Commercial" as including small and medium business and agricultural). NCI also valued reliability improvements as a benefit for the utility or network operator, ultimately passing to customers through cost reductions, using a value for all avoided unserved load of $5,000/MWh.

Table 2. Sustained outage customer value of service

Customer Class	Value of Lost Load per MWh
Residential	$2,500
Commercial	$10,000
Industrial	$25,000

Source: NCI

The researchers incorporated these values but priced reliability improvements based on the actual customer class makeup of each affected circuit.

2.3.2. Power Quality

In its study, NCI defined the benefit "power quality" as a reduction in dynamic voltage swings, particularly where such swings could result in interruptions of customer processes. DER (or presumably other measures) that could reduce the occurrence of such events by reducing voltage sag was ascribed a power quality benefit. This benefit would accrue to customers. Reduction in such power quality (PQ) events that interrupt customer processes are one of three benefits NCI ascribed to the voltage impacts of DER.

NCI provided an interruption and voltage sag rate distribution from the New York State Energy Research and Development Authority (NYSERDA) showing the voltage deviation or PQ events experienced by customers in terms of the resulting, or "remaining" voltage relative to the site's actual average (presumably steady-state) delivery voltage. This distribution indicates that where a given customer site may experience, on average, 66 "meaningful" PQ events resulting in voltage below 90% or above 110% of the site's average voltage, in 80% of these events the remaining voltage is at or above 75% of the site's average delivery voltage.

NCI also provided an Information Technology Industry (ITI-formerly CBEMA) Threshold Curve. This curve shows that for long-duration (≥ .5 sec) PQ events, voltage deviations below 80% or above 120% of *nominal* voltage at the customer site would be expected to result in process interruption (or interruption in the function of on-site devices) and possibly equipment damage. (The curve shows that over shorter PQ event durations equipment has greater voltage deviation tolerance.).

Overlaying the expected distribution of PQ events in terms of severity relative to average delivery voltage with the impact of PQ events based on deviation from nominal voltage implies a relationship between actual delivery voltage and the frequency of PQ events that could cause process interruptions. Specifically, sagging voltage at a customer site could increase the share of minor but common PQ events posited in the NYSERDA event distribution that result in delivered voltages outside the ITI voltage tolerance envelope, causing interrupted customer processes or equipment damage.

In other words, sagging voltage at a customer site could increase the share of minor but common PQ events posited in the NYSERDA event distribution to result in delivered voltages outside the ITI voltage tolerance envelope, causing interrupted customer processes or equipment damage.

NCI estimated the aggregate economic impact of PQ events in a system the size of the Hobby system at $20 million annually. Accordingly, a 10% reduction in the number of such events would yield customer benefits of $2 million annually.

NCI also provided the power quality Value of Service values shown in Table 3. According to NCI, these values are derived from studies by LBNL and others.

Table 3 suggests that nearly all of the cost impact of PQ events falls on commercial and industrial customers; even if commercial and industrial customers represent only 10% of the customer base, the share of PQ events that result in interrupted processes at those locations and the dollar cost per event are far higher.

Table 3. Power quality value of service

Customer Class	$/event	% Interrupted Processes from Major PQ Disturbance
Residential	$4.34	15%
Commercial	$1,073.48	20%
Industrial	$3,396.79	35%

Source: NCI

The results of this study include a great deal of detail on the voltage impacts of individual network improvement measures. However, given the timing of the two sets of results the researchers modified the NCI approach only slightly. The approach of the researchers was to assess whether a 10% reduction in PQ events postulated by NCI was realistic for network measures given the simulation results (and that the $2 million annual customer benefit was achievable), and then allocate the benefit to individual measures based on their voltage impact. The delivery voltage-PQ event frequency relationship suggested in the NCI study combined with the Energynet® model offers the opportunity for much more detailed, individual customer level assessment of power quality impacts.

2.3.3. Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) refers to the practice by the network operator of reducing customer delivery voltage, thereby reducing consumed and generated electrical energy (MWh). For pure resistance loads power consumed is proportional to the square of the voltage, while for pure inductive loads, power remains constant as voltage varies. Studies conducted in utility systems having a wide range of load compositions have shown that a reduction in voltage of, say, 3% will result in a proportional reduction in consumption of 3%.[17] CVR is related to voltage in that it can only be implemented where voltage profiles are sufficiently flat to allow a voltage reduction while keeping the lowest voltages above minimum voltage specifications.

NCI refers to CVR as an "energy efficiency" benefit category. To the extent that DER (or any other measure) improves voltage profiles to allow delivery voltages to be reduced while remaining within specifications, NCI would ascribe an energy efficiency benefit. The benefit, in the form of energy not generated, yields a cost savings that ultimately accrues to ratepayers. Enabling CVR is one of three benefits NCI ascribed to the voltage impacts of DER.

In its study, NCI investigated the potential for reduced energy consumption through conservation voltage reduction. NCI reported that SCE indicated that many distribution feeders in the Hobby would not be eligible for CVR due to concerns regarding voltage drop within the feeder and/or performance degradation for large commercial and industrial customers whose loads are often constant power or served by induction motors with large reactive power requirements. NCI determined, therefore, that only circuits with no industrial, large, or medium business loads were eligible for CVR.

NCI also did not have specific data indicating the impact of the 2005 Optimal DER Portfolio projects on circuits that could be candidates for CVR. The 2005 Optimal DER Portfolio projects included subsets of projects identified as providing voltage benefits; however, at the time this voltage benefit was characterized in terms of their impact on the systemwide minimum voltage only, not on the voltage variability within individual circuits.

NCI posited that, for eligible feeders, voltages would be lowered by 1.00% (0.01 PU) under summer peak conditions and 0.25% (0.0025 PU) under winter peak conditions. This would result in proportional reductions in energy consumption in kWh terms. NCI assumed a 53% load factor for CVR and valued the energy savings using the seasonal energy values in Table 4.

None of the simulations the researchers had performed was set up in anticipation of conservation voltage reduction as a specific voltage-related benefit category. Thus for purposes of this benefit category, the researchers adopted the NCI approach, basically concluding that a given level of CVR is possible on certain circuits based on their customer makeup. Those results are presented in Section 3.

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17. H. Lee Willis. New York. 2004. ***Power Distribution Planning Reference Book,*** CRC Press.

The researchers believe a more evolved approach to this opportunity is to make direct assessments of individual circuits or families of circuits for their CVR potential using the Energynet® simulation, and to directly assess various measures' impact on the CVR opportunity through similar simulations. An example of such an assessment for a family of circuits in one substation is also provided in Section 3.3.4.

2.3.4. Bulk System Capacity

This project defines "capacity" as a standalone commodity, whose value depends on the conditions under which it is available and the location at which it can be reliably scheduled for delivery. The researchers see a resource's ability to provide incremental capacity as a permanent benefit, valuable as long as the resource is demonstrably available, and not merely a deferral. Subject to market rules, demand response, distributed generation and storage can provide such capacity. Ancillary services capacity is a specialized type of capacity, and capacity associated with DER cannot count as both bulk system capacity and ancillary services capacity.

In its evaluation of the Optimal DER Portfolio projects, NCI established different values for capacity depending on when the capacity is available. These appear in Table 4. These values are derived from SCE rate case data and reflect an effective reduction in capacity needed for reserve margin and a loss benefit for capacity located in the load center.

Table 4. Seasonal capacity value

Period	$/kW-yr
Summer on-peak	$56.785
Summer off-peak	$8.108
Winter on-peak	$6.081
Winter off-peak	$4.054

Source: NCI

It is clear from Table 4 that resources' capacity value of bulk system will be largely dependent on their availability during peak periods. In addition, NCI does not state whether there might be a declining value of bulk system capacity if a large amount of incremental capacity is made available from a given measure.

Demand response, as an energy-limited capacity resource, would have to meet minimum availability requirements to be valuable as bulk system capacity. NCI quoted the minimum availability figures in Table 5.

Table 5. Demand response availability

Sector	Availability (hrs/yr)
Residential and Small Commercial	300
Large Commercial and Agricultural	100
Industrial	200

Source: NCI

As the researchers developed the Optimal DER Portfolio projects, it was assumed that residential and small commercial demand response would only be available during super-peak periods – or 1% of the hours of the year – more limited than the values in Table 5.

Under California Independent System Operator (California ISO) rules, resource adequacy capacity could potentially have additional value if it helps address a defined "local capacity requirement."[18] The researchers did not attribute incremental local capacity requirement value to the bulk capacity value of measures or resources for purposes of this analysis, nor did the researchers apply different bulk capacity values to different locations within the Hobby system. So for the purposes of this section bulk system capacity, value is not location-specific within the Hobby system.

The researchers used the values in Table 4 to price bulk system capacity associated with measures or resources depending on the period when each is available. The researchers attributed capacity value to demand response, distributed generation, and storage.

The researchers viewed ancillary services capacity as mutually exclusive with bulk system capacity, and where measures or resources could provide ancillary services at a higher value the researchers used those values instead.

2.3.5. Ancillary Services Capacity

NCI assumed that, among DER resources, some resources could provide 10-minute operating reserve capacity, 30-minute supplemental reserve capacity, or regulation capacity (as a matter of nomenclature, the researchers will interpret "operating reserves" as "non-spinning" reserves and "supplemental reserves" as "replacement reserves."). NCI states that only residential HVAC demand response is suited to serve as operating reserves because the capacity must be available any time and as consumers would have to opt in, many non-residential customers would decline. NCI states that only storage is suited to serve as regulation, which must be available to adjust positive or negative on a real-time basis.

CERTS demonstrated the ability for demand response resources – even legacy HVAC load cycling – to provide spinning reserve capacity on a sustained basis. In that study spinning reserves were presumed to be available within 10 minutes; the study showed the possible response as near-instantaneous. CERTS further demonstrated that demand response resources

18. California Independent System Operator. November 2009. ***2011 Local Capacity Area Technical Study*** draft manual. Available at <http://www.caiso.com/2464/24647c7416830.pdf>.

might be called repeatedly for periods typical of spinning reserve deployments (5–20 minutes) without customer complaints. This is an important finding as it suggests that demand response may serve as reasonably durable spinning reserve capacity, and with spinning reserve calls of short enough duration, the dispatch limits on HVAC load cycling demand response may not be a major factor.

CERTS also shows that spinning reserve prices are typically three times higher than non-spinning reserves (and five times higher than replacement reserves), and argues that a resource that is capable of providing spinning reserves should be thus used if possible.

Based on the foregoing, the researchers assume that demand response can potentially provide spinning reserves or non-spinning operating reserves subject to its availability and market needs, and that storage can potentially provide regulation reserves during peak periods, again subject to the system's needs. The researchers view the real power output of dispatchable distributed generation as generally controlled by the site host or customer, in which case distributed generation has bulk system capacity value, but it would not offer the operational flexibility to serve as spinning, operating, or replacement reserves.

As an indicator of the market's appetite for ancillary services, E3 in its avoided cost methodology shows data indicating that in general within the California ISO system, purchases of spinning reserves and non-spinning plus replacement reserves are each fairly constant at about 2% of load, and that purchases of spinning and non-spinning reserves are relatively constant during the day.

NCI provided ancillary services capacity values for non-spinning reserves, regulation, and replacement reserves. CERTS in their study indicated that spinning reserve prices are typically 3 times higher than non-spinning reserves, so the researchers used that to derive a spinning reserve value from NCI's non-spinning reserve value. These values are shown in Table 6. NCI does not specify any seasonal variation to these figures. E3 states that in the California ISO ancillary services prices have been slightly higher in summer and winter months than during spring and fall, and that peak prices are generally, though not always, higher than off-peak prices. Therefore, the researchers assumed these values would persist and applied these values for winter and summer, on, and off peak.

Table 6. Ancillary services values

Type	$/kW-yr
Spinning Reserves	$45.00
Non-Spinning Operating Reserves	$15.00
Regulation Reserves	$20.00

Source: NCI

During summer peak periods the bulk system capacity prices established by NCI are close to (and slightly higher than) the highest ancillary service price noted above; thus during summer peak periods the potential value opportunity from ancillary services is arguably captured in the bulk system capacity value.

During winter peak and off-peak periods there is an incremental value opportunity for demand response and storage resources available during those periods, subject to the system's requirements. Under winter peak conditions the spinning reserve opportunity for demand response and the regulation reserve opportunity for storage would each be limited to 13.5 MW, and under off-peak conditions, the spinning reserve opportunity for demand response would be limited to from 6.7 to 9.8 MW, in each case about 2% of load during those periods.

2.3.6. System Voltage Security

Very quick load reductions in sufficient quantities, particularly the disconnection of loads such as HVAC units that might otherwise stall and contribute to the event, can prevent voltage-related contingency from propagating and leading to system voltage collapse. This is the basis for system voltage security as a benefit category.

Under this approach, this benefit for the system voltage security is a function of the amount of HVAC cycling demand response available in the system, and is thus related to capacity. The benefit is unavailable until the demand response reaches a certain high penetration level. This benefit is additive to the other capacity-related benefits, principally ancillary services, attributable to this demand response capacity.

NCI postulates that residential and small commercial demand response in the form of HVAC cycling (and also DER as synchronous generators) can provide dynamic real and reactive support to keep systemwide minimum voltage above 70% of nominal (0.70 PU) for a short period following a contingency. In sufficient quantities and with the proper controls and instrumentation, these resources could thereby reduce the risk of system voltage collapse. This requires a very high penetration of such DER (primarily demand response) and appropriate communication and controls or local relays to issue a signal following a contingency and achieve shutdown of individual HVAC devices within 0.5 seconds.

NCI judged that a "high" penetration of 88.7 MW of residential and small commercial HVAC cycling demand response capacity, or 6.6% of area peak load, would be enough to mitigate a systemwide voltage collapse event, but that 37.8 MW or 2.8% of area peak load would not be enough.

For the Hobby system, NCI postulates an illustrative system collapse event of 10 hours with up to 1,300 MW of load at risk (the system's entire load under super-peak conditions). NCI estimates the value of unserved energy under such an event at $40,000 per MWh. This value is derived from the impact of other such system collapse events such as the August 2003 regional Midwest outage. NCI considered this a utility/ratepayer benefit (presumably analogous to the utility/ratepayer benefit associated with reliability improvement).

In NCI's analysis, under a "high penetration" scenario, based on a 1.5% likelihood of a contingency that could trigger voltage collapse combined with a 3% likelihood that loads would at the same time exceed a collapse threshold, NCI judged that this capacity might avoid one such event every five years, with avoided unserved energy of $300,000 to $400,000, and an annualized benefit of about $90,000. Again, this benefit is unavailable except for very high penetrations of HVAC cycling demand response. This benefit is additive to the other capacity-related benefits, principally ancillary services, attributable to this demand response capacity. NCI determined that system voltage security is a direct benefit to utility customers.

2.3.7. Energy

In its assessment of the 2005 Optimal DER Portfolio projects, NCI priced the energy produced depending on its dispatch profile using the values in Table 7. NCI stated that these values are based on avoided energy costs for those seasons.

Table 7. Seasonal energy value

Operating Profile	$/MWh
Summer peak & Winter Peak	$98
Summer peak only	$150
Year-round	$75

Source: NCI

NCI assumed that 30% of energy from DER would provide congestion relief, and applied congestion relief values of $1.00/MWh for distributed generation and $0.50/MWh for demand response and storage. NCI states that these values reflect the fact that the Hobby system is modestly constrained. This value differs considerably the $15–$20/MWh congestion value stated by TIAX.

For this project's purposes, the researchers have used the NCI energy values, and applied a $1.00/MWh value for congestion relief to all energy during peak periods. The researchers also state the congestion component separately, so the bulk energy value contribution can be excluded.

For determining the energy value associated with demand response, the researchers took into account the resource's operating limitations. NCI proposed the annual limits to be applied to demand response resources shown in Table 5. The researchers adopted these with the exception that residential and small commercial demand response would be limited 88 hours per year, or 1% of the total hours. Further, the researchers assumed for the 2005 cases that all of the energy "production" from demand response other than the super-peak-only resources would be during periods other than the super-peak. In other words, the researchers assumed that demand response capacity was generally available, but that more flexible demand response resources would actually be used outside super-peak periods given the volume of demand response available during those periods.

2.3.8. Loss Reduction

The Energynet® simulation uniquely permits direct assessment of the loss impacts of network performance enhancement measures in both transmission and distribution over a variety of operating conditions through simulations.

NCI evaluated loss reduction in terms of energy savings and in terms of reduced peak demand. Thus, the researchers priced this benefit by applying the bulk energy and bulk capacity values stated above.

2.3.9. Emissions Reduction

NCI attributed emission reduction benefits to DER as PV generation, demand response, and energy storage. NCI also developed a combined emission reduction value of $0.00089/kWh incorporating the emission rates and values for emissions of carbon dioxide (CO2), sulphur oxides (SOx), nitrogen oxides (NOx), and particulate matter shown in Table 8.

Table 8. Emission values

Emission Type	Marginal Emission Rate (lb/kWh)	$/lb
CO2	0.819000	$0.005
SOx	0.000004	$3.450
NOx	0.000210	$4.629
Particulate	0.000137	$6.475

Source: NCI

The researchers attributed theses values to the net energy production of PV distributed generation, demand response, and storage, and to the loss reduction attributed to those resources. The researchers also attributed this value to the loss reduction associated with non-supply measures.

2.3.10. Load Relief

This project's approach in this benefit category departs in a significant way from the entire premise of capital expenditure "deferral." Instead, this project approaches the topic from the standpoint of "load relief." A measure provides a "load relief benefit" if it relieves a demonstrated overload, irrespective of any T&D capital expenditures that might be planned. This overcomes two limitations of a "capital expenditure deferral" approach – first, that a real or anticipated overload may not have a planned capital project tied to it, and second, that a planned capital project may not relieve a real or anticipated overload. Assessing measures for their load relief benefit allows an objective, side-by-side comparison of network expansion and non-wires measures such as DER.

The researchers' model of the Hobby system with 2011 forecast loads allows them to determine the actual constraints in the system with anticipated loads before any remediation, at least under "normal peak" conditions. The researchers can then make an objective assessment of the load relief that is needed as well as the load relief that might come from potential network performance improvement measures.

Valuing "load relief" in economic terms remains somewhat problematic. Where there are network expansion capital projects identified to address a demonstrated constraint that could be deferred, the cost of these projects (or the value of their deferral) is one measure of the value of this load relief. For purposes of this project, the researchers have treated the annual carrying cost of a project that would eliminate a demonstrated constraint as the annual value of that load relief. NCI provided an annual carrying cost of 15% of the total capital cost of a project, and the researchers used this figure to derive an annual value for load relief.

Equating the value of load relief to the annualized cost of a specific network expansion project shown to relieve does not effectively address the "chunkiness" of most network expansion projects. The incremental load-carrying capability provided by a given project may not match well the demonstrated constraint, though a persistent constraint may "catch up" with the added capacity from a network expansion project over time if the load continues to grow. A series of annual forecasts and assessments would at least make this transparent. The researchers also do not have a good way to estimate the value of load relief for which there is no proposed capital project.

2.3.11. Nominal vs. Firm DER Capacity

Key considerations in the evaluation of the network benefits of DER are whether the resource can be dispatched when needed and for the required duration, whether the resource is available when called, and whether the communication and control systems are in place to enable the network operator use the resource for the desired outcome and even to verify its performance.

NCI refers to DER meeting these requirements as "equivalent firm" DER capacity. NCI states that equivalent firm DER capacity must be equally reliable as traditional capacity additions; thus if a feeder has average availability of 99.99%, then a feeder with DER would also have to have an average availability of 99.99%. Some approaches, including possibly NCI's, would significantly discount the nominal capacity of a DER project to reach an "equivalent firm" value.

E3, in advising caution in extending its avoided cost methodology to distributed generation, states that for distribution generation, if only one generator is installed in an area, that generator may not allow for any distribution capacity avoided costs because the utility may need to provide sufficient capacity to meet distribution peak demand when the generator is out of service. However, if multiple small base load distributed generator devices were installed in an area, and those generators had independent failure modes, then the utility may be able to avoid distribution capacity costs – just as with energy efficiency programs.

CERTS argues that the statistical reliability of a large population of very small, independent distributed resources is much higher than the statistical reliability of a small population of large conventional resources even if the reliability of the individual distributed response resources is lower, and also that verification of the performance of individual resources is not necessary.

In these results the researchers have not explicitly maintained different values for nominal capacity and "equivalent firm" capacity (though the researchers could easily do so). As the researchers consider DER capacity as a network element, the nominal capacity of a given resource in this project's rubric is the capacity available to the grid. The nameplate capacity of the physical resource could be different. Resources are limited in terms of their time and duration of availability (e.g., PV is not available at night, and demand response is available only on a limited basis). The researchers do explicitly assume the existence of the necessary institutional, commercial, and physical measures to use these resources as described.

DER additions can also provide VAR support either through incremental capacity or by reducing the system's VAR consumption. VAR consumption reduction is valuable as a benefit; the researchers considered VAR consumption reduction as a benefit in the SVP Project, and NCI valued reductions in VAR consumption in terms of avoided costs of new capacitors, However, consistent with the researchers' approach to load relief and capacity deferral, a nominal reduction in VAR consumption may not necessarily defer or avoid capacitors that would have been purchased. Further, the researchers' studies show that there is excess reactive capacity in the Hobby system in some locations already, and little need for additional reactive capacity; thus, the true value of a reduction in VAR consumption in terms of avoided capacitor purchases is very small.

2.3.12. Benefit-Cost Ranking

The network performance enhancement measures considered in this project cover a wide range of benefits accruing to different stakeholders and have different capital and operating cost expenditure profiles. In particular, for any given decision-maker there may be both direct and indirect costs, and both direct and indirect benefits. Therefore, the decision-making process to evaluate these resources is multi-faceted.

In Section 3 this report provides a cost-benefit assessment of the network performance enhancement measures considered. The benefits valued for each group of network performance enhancement measures are summarized in Section 2.2.

Only the utility-proposed network expansion projects and the capacitor additions have specified capital costs associated with them, which lends themselves to a simple cost-benefit analysis – in this case an assessment of the annualized benefits relative to the annualized costs. Implicit in this approach is that while the benefits of a given measure may accrue to different parties, the annualized costs accrue to (or are recovered from) utility ratepayers.

Some measures such as recontrols or networked topology have no explicit capital costs, though there may be indirect costs to implement such measures, such as costs of distribution automation needed to implement the posited configurations.

In its study, NCI posited a 15% annual carrying cost for capital projects, which the researchers used to annualize "one-time" capital costs.

In the case of demand response, distributed generation, and storage, the party incurring the capital cost is entirely dependent upon the business model. For example, demand response up to a certain penetration may be a fully funded initiative, with essentially no incremental cost to targeted demand response to secure the individual Optimal DER Portfolio demand response and its system benefits. Distributed generation may be essentially entirely funded by the host customer, allowing for incentives, which are also a previously fully funded initiative. In the case of demand response, distributed generation, and storage, the researchers simply quote the relative benefits without determining a cost-benefit ratio.

2.4. Network Monitoring

One of the core research goals of this project was to validate the Energynet® model with field conditions, which, in turn, would require the collection of field data to compare to simulation results under a specific set of conditions. Well into the project, the researchers developed a demonstration plan to obtain these field data and conduct tests to validate the simulation as well as achieve other objectives. The researchers included in the field demonstration plan an element to augment existing field instrumentation in the Hobby system to provide comprehensive and dispersed field data on real and reactive power flow and voltage to provide a temporary data gathering and collection infrastructure to obtain field-read data that may be compared to power flow results from the Energynet® Simulation.

2.4.1. Augmenting Current, Power Factor, and Voltage Instrumentation

Working with SCE, the researchers established a basic functional specification for network monitoring to be employed in this project:

- Circuit per-phase current and power factor measured at the circuit source.
- Substation bus sending voltage.
- Circuit voltage measured at enough points to derive a voltage profile for the circuit.

The researchers felt that power factor along with current was essential to validate the simulation's power flow results even if not strictly necessary to assess line loading in a distribution system management sense. The researchers also felt that the ability to measure voltage profile along circuits and compare it to the calculated results might help validate the load distribution and line impedance assumptions that are embedded in the model.

This "monitoring density" specification was a compromise in that a) it does not address power flow (i.e., current and power factor measurement) variation along the feeder, and b) it does not ensure the distinction of system conditions on different legs of "Y"-shaped circuits.

With the emergence of devices destined for "smart grid" deployment, many modern distribution devices now provide a variety of system condition measurement along with embedded communication supporting remote reporting. One of the elements of this project's approach was to make maximum use of the instrumentation already installed in the Hobby system.

Once the existing system instrumentation was identified, mapped to the system model's topology, and assessed for gaps relative to the monitoring specification, the project would need to identify augmenting instrumentation acceptable to SCE providing, ideally, current, power factor, and voltage; or, short of that, instruments measuring current and power factor with separate instruments for voltage. Ideally, these sensors would be remotely readable, interoperable with SCE's legacy communication system be quick and easy to install where needed, would address the need for instrument power, and would last through the expected duration of the testing and beyond.

2.4.2. Remote Reading and Data System Integration

It was the researchers' strong desire, in order to support the field verification with simultaneous system and load data, to provide augmenting instrumentation that could be read remotely, and to integrate the data received with SCE's existing power system data management systems. This would also provide real-world experience integrating data from different sources to leverage legacy instrumentation in a move toward more wide-area monitoring to support smart grid applications.

This would require that the researchers select augmenting instrumentation devices with which the researchers could successfully support some sort of remote reading capability, and that the researchers successfully establish a point of integration to merge that data into SCE's field data systems.

2.5. Operational and Planning Applications

The successful demonstration of relatively rapid updates of the Energynet® system model introduced the possibility that the Energynet® method could support operational decision-making even in light of frequent system changes. As noted in Section 3.1.1, SCE representatives promoted this possibility.

Accordingly, one of the elements incorporated in the field demonstration plan was a goal to explore the practicality of more frequent updates of the Energynet® simulation model to reflect essentially ongoing system changes; that is, to obtain simulated conditions of the subject system within the week or day. By comparison, the researchers had expected that the basic model update for the field verification originally contemplated at the outset of the project might be months old when conducting particular tests field validation tests.

The contemplated field demonstration plan would include implementation of data transfer infrastructure to reduce the human steps otherwise needed to gather and deliver data to update and populate the system model. Meeting this goal would offer the potential to use the high-definition model to address operational questions and more dynamic system behavior. Implementing this infrastructure would also yield real-world experience in the integration, management, and use of the dissimilar, dispersed data sources needed to support a living power system simulation

Based on the experiences gained from developing the initial system models, the researchers viewed the most dynamic data sources for the Hobby Energynet® model to be the system data itself, which would change with every change in the "normal" physical layout of the system, and data from the SCADA system and distribution monitoring devices, which the researchers knew would change constantly. The researchers planned to implement some method to automate the receipt of data from these sources, at least partially.

A related consideration was how to deliver the results of the Energynet® processing of these data to users other than the project team. A third consideration was security of the source data both before and after processing. All of the source data are SCE proprietary, and some are subject to the Federal Energy Regulatory Commission's CEII non-disclosure agreements as well.

The field demonstration plan budget was framed originally based on one or more servers at SCE to support these data bridges. However, based on all of the considerations the researchers committed to an entirely Web-based infrastructure for both the receipt of data from SCE and the management of data within the Energynet® model, using secure Web services to move data between its sources and where it would be used. The researchers believed this would provide greater security, reliability, and scalability than a local site, even one at SCE, and would support data update streams of any frequency.

Once the data transfer and management infrastructure was in place, the researchers expected to conduct a series of "updates", each with a new "initial" power flow solution. The objective here was not necessarily to demonstrate specific operational applications, but to demonstrate the feasibility of using this methodology to support a frequently changing system.

2.6. Verification of Methodology

The Energynet® simulation models out of necessity incorporate a significant amount of infill data to reduce handwork to a manageable level. Thus, a core research goal of the project was to validate the Energynet® method's characterization of a subject system and its simulation of conditions within that system with field measurements.

To support this goal, the field demonstration plan included a comparison of field-read system condition data with system condition data derived from Energynet® simulations under a range of conditions to assess how well the Energynet® Simulation reflects actual conditions. Meeting this goal will help to validate the use of the Energynet® method to simulate actual systems and conditions.

The system-monitoring infrastructure described above provides a nominally gap-free, area-wide network of system monitoring points. With specified monitoring density and the targeted citing and integration of augmenting instrumentation, essentially all of the nearly 250 feeders of the Hobby system have some condition monitoring within this infrastructure. The researchers were able to use SCE's legacy communication and data management systems to collect data from these devices and archive them for later analysis. Using the data bridges the researchers implemented to support operational applications, these data are directly available to the Energynet® simulation of the Hobby system.

The researchers were thus able to develop simulations of the Hobby incorporating system data from a particular, recent date and load data from a date very near or on that same date. The researchers were able to compare simulation results with system condition data taken from field instrumentation contemporaneously with the load data.

In comparing simulated results with field data, the researchers considered megawatt (MW) flow, megaVolt-Amps (MVA) flow, and current flow in particular line segments, and voltage at particular points. The researchers had field flow reads mapped to individual line segments within the Energynet® model at approximately 214 points, all on different circuits, with the system. The researchers had field voltage reads mapped to individual system devices at approximately 650 points, also widely dispersed within the system.

3.0 Outcomes

3.1. Model Development

One of the core research goals of the project was to demonstrate the application of the Energynet® method with its high-definition datasets in a larger system and using source data routinely maintained by a utility typical of California's utilities. The following results fully accomplish this goal.

In the case of the Hobby system the researchers produced from different source data 15 separate models, 7 reflecting the subject system on different "system dates," and 8 reflecting different possible future configurations. All are verified as having no unintended islands or inter-circuit ties. All but a few interim cases are populated with loads derived from actual SCADA records for a variety of conditions or forecasts and represent fully solved power flow simulations. The researchers have demonstrated going from raw utility data to a complete, checked model with several processing iterations in as little as a few days.

The researchers believe these are the only examples of the successful development of integrated T&D power flow models of this scale from repurposed utility equipment and system data.

The most fundamental issue was the availability of data of sufficient quality to support such a model. The dataset supporting the Energynet® simulation is in large part a power flow dataset. It is important to note that at the most basic level in a bus/branch power flow dataset[19], every bus must be a line-end, every element of the dataset must be connected to every other element via a "line" in the model, and every line and element must be fully and completely characterized. This level of connectedness and thoroughness in characterization is not needed and was not present in any of the source data, individually or in aggregate. In this project's approach the researchers are, in effect, adapting the source data for a purpose other than what was intended; deficiencies the researchers encounter for this project's purposes in no way suggest deficiencies in the data for their intended purpose. Reaching this level of connectedness and completeness from available source data is the fundamental challenge of high-definition power system simulation models.

In the SVP project, the Energynet® dataset comprised about 850 SVP buses. About 37 buses represented SVP's local transmission, which SVP had previously modeled; the rest of the buses, characterizing about half of SVP's distribution circuits, represented newly modeled dataset elements. These elements had been integrated into a west-wide transmission model for the Energynet® dataset. In that project the "new" model data characterizing the distribution elements of the SVP model increased the size and detail of the overall the system model by

19. Commercially-available power flow software packages such as GE PSLF require bus/branch network datasets in one of several formats. The Common Information Model (CIM) promoted by the Electric Power Research Institute is a higher-level data structure with more specific characterization of line-end network components (buses) depending on their function.

about 23 times. Those added data had been developed largely by hand, using takeoffs from engineering drawings and circuit maps.

In early discussions on this project, the researchers estimated that the distribution portion of the Hobby system that would be newly modeled would comprise about 9,000 buses, or about 10 times the size of the SVP system model. However, once the researchers began to extract device and line characteristics from the source data for the first sample circuit, it became evident that this projection would not hold. It appeared that the first circuit alone would comprise over 1,000 buses, and even if the remaining 200-odd circuits were shorter and less complex, the distribution portion of the model might have 90,000-100,000 buses, or an increase in size and detail of over 3,000 times, all of which would be characterized with newly developed model data.

In light of the apparent size of the final Hobby model, the researchers agreed with the Energy Commission contract manager that the by-hand approach to dataset building that was used for the SVP project was not practical (and would not serve the project objective of demonstrating the practicality of this methodology). Thus, automated processing of the source data to produce the model became the primary method for dataset building for this project. This would require reducing the model-building methods employed in the SVP project to software to permit their automation. While this software approach ultimately proved successful in terms of its performance and practicality, its initial implementation was more difficult than the researchers had anticipated.

At the outset the researchers judged internally that the software approach essentially would need to stand in for the engineer's role in the approach used in the SVP Project. That approach was to perform all infill to complete any missing data, and to resolve data inconsistencies. This meant that for a system this size, it would need to yield line and bus results that are 99.9% correct or better for the remaining true "hand" work to be reasonably practical. Even this standard of performance would leave, for example, 100 lines in a 100,000-line model with issues requiring human resolution.

Using context-sensitive software algorithms and scripts, the researchers extracted the needed characteristics of all of the devices and lines of the Hobby distribution system from the sources identified above. Other than the single-line diagrams, most of the data sources were machine-readable or could be made to be machine-readable.

Integrating data from a variety of sources was essential. The researchers used software algorithms to reconcile differences in numbering and naming conventions from different data sources to allow them to ingest, evaluate, and eventually deploy data from different sources.

Infilling for missing data was a persistent challenge. The software employed algorithms incorporating approaches approved by SCE to perform context-sensitive infill for missing data for load-serving transformer ratings and line conductor specifications. The software also used algorithms to determine all of the connection details of intercircuit ties as well as their normal and alternate configurations. The researchers also employed software algorithms to add impedances and ratings for every line segment and transformer from several external sources.

The line impedances and ratings are specific to each line's construction and conductor material, and in some cases, its operating voltage.

The researchers used software algorithms to ascertain the correct connections for devices lacking connections to lines, lines not connected to devices, groups of lines and devices not connected to the main system block, and missing line segments connecting devices in the source data. The researchers also implemented algorithms that would detect and resolve spurious switch positions that could create loops or unintended ties between circuits.

Correctly incorporating circuit-level system data in a systemwide model required that the researchers identify, through software, parent-child relationships for secondary and tertiary substations served from distribution feeders. These had been characterized in general terms, but not at the necessary device level of detail or with identification of preferred, normal, alternate, and looped feed paths.

The researchers used geo-coding techniques to determine the circuit and device-level connection to the power delivery system of devices not "connected" in the source data, including most of the existing distribution-connected generating units in the subject system.

One of the initial early considerations was whether to develop a three-phase model. In SCE's case, they did not have the data available to identify different distribution phases that serve their appropriate loads, so for this deployment the question was moot.

The researchers also used software algorithms to process the SCADA archive data to determine MW and MVAR loads for each circuit as well as line and station capacitor operation and distribution-connected generator operation. The researchers implemented algorithms to perform context-sensitive infill where required, incorporating approaches agreed to by SCE. SCE also reviewed the circuit-level load results for reasonableness. The researchers adjusted the circuit-level loads for the contribution of secondary and tertiary substations and circuits, capacitors, and embedded generators; the researchers then extrapolated loads of individual load-serving devices on each circuit from these results. Integrating this data proved to be difficult, due to a range of factors including naming conventions and data formats. The researchers implemented three different approaches with partial success. The final method, with data transferred directly over the data-bridge developed for the field trials, proved the most successful.

This software data processing yielded a set of input datasets comprising distribution detail and local transmission for the Hobby system suitable for direct import into a power flow program such as PSLF or GRIDfast™ in a merge with the WECC regional transmission dataset. The researchers accomplished this data merge in both environments.

The researchers were able to confirm through testing that the merged dataset characterized the system with no spurious ties between circuits and no unintentionally islanded buses. All load serving devices were represented, with no duplicates, with device-level and circuit-level loads consistent with SCADA reads. Real and reactive power resources were also represented, with their output consistent with their operating characteristics, SCADA records where available, and internally consistent within the model dataset.

The software achieved the goal of 99.9% accurate bus-line relationships; the only matters requiring human attention were to correct for duplicate devices or device identifications in the source data that the software could not distinguish. For the 2005 model, this represented a few dozen individual fixes that were eventually automated.

Model "accuracy" presents a definitional problem, as only about 60% of the source data were used as-is, without modification, infill, or interpretation. The researchers believe that near total hands-free data processing enables very accurate translation of source data with only intended, systematic modifications. The researchers' previous experience was that unintended errors nearly always occurred in steps requiring human intervention.

The researchers found that the initial power flow solutions themselves were a very effective screen for data errors. A power flow solution can only be obtained if in aggregate the individual loads, resources, lines, and devices modeled in the dataset represent a "feasible" combination. In other words, a dataset can be nominally "complete" with no missing elements, and "connected" with no unintended islands and still not represent a feasible system in terms of a power flow solution. In particular, extraordinarily large power flow models with very small-impedance lines are inherently incapable of accommodating values in the dataset that are even slightly out-of-bounds. The researchers found great success applying model-building tools to scouring datasets for the 1-in-100,000 incorrect value preventing a power flow solution, and the researchers learned that a solvable dataset, particularly in PSLF, must be and is essentially free of such errors.

Given the amount of data manipulation required, ultimately the test of an Energynet® simulation lies not in its adherence to the source data or even the lack of out-of-bounds values in a power flow dataset, but its verification against field measurements gathered from sensors. At its absolute worst, a validated simulation is a starting point from which underlying data can be verified as appropriate and on a case-by-case basis if they affect operational or planning decisions.

3.1.1. Model Updates

Once the initial Hobby system model was completed, the researchers conducted a timed test for the development of the Mountain system model, comparable in size to Hobby. This model was completed in less than a month. The researchers also completed a timed test of an update of the Hobby system model using late 2007 system data in less than 15 business days. The researchers completed a second update of the Hobby model using late 2008 system data.

From the 2007 update results, SCE representatives concluded that this shorter duration for creating a complete model gets within time frame of potential interest for actual production-type work, especially if smaller scale/incremental updates may reach sub-day update time frames. This even more ambitious update timeframe evolved into the operational and planning applications element discussed in Section 2.5 and Section 3.5.

3.1.2. "2009" Model

The researchers developed a 2009 update of the Hobby system model to support the model validation elements of the project. This update used the same basic system data sources. To perform this update the researchers obtained new data from SCE characterizing the Hobby system, and new data reflecting Hobby system loads and device status. The researchers did not obtain updated data for distribution-connected, customer-owned generation, noting here that the projects the researchers include in the model are over 25 kW, and the researchers assumed there were few changes in this inventory that would substantially affect the model results.

The source of load data and device status data would be the same as previously, SCE's SCADA and distribution control and management DCMS systems. However, rather than selecting "peak" days, the researchers hoped to gather data for multiple days for use with this updated model.

The researchers would use the Energynet® software to process this data, infill where necessary, and generate a dataset for use with PSLF and GRIDfast™ .

In the updated model, approximately 15,000 buses are part of the regional transmission model provided by the WECC, and nearly 100,000 buses (and their associated lines, transformers, loads and resources) are added through the researchers' efforts. This added detail makes the model "high-definition." Thus nearly 90% of the finished, combined model is "built" using the Energynet® software. The researchers believe that in most applications of power flow software and related analyses the model development step is a relatively minor element. In contrast, in applications such as the one demonstrated in this project, dataset building is the major consideration.

This project's process and tools for ingesting and processing system data from the various sources and developing high-definition, integrated transmission and distribution datasets for use in power flow applications are essentially the same as the researchers used to support the 2005 models, but much more highly evolved and mature. First, the process is nearly entirely hands-free. Raw data from the utility is placed in a directory on a server, and the results are written to another directory within hours. Second, the resulting files are in an "*.epc" format that can be imported as written directly into PSLF and other third-party power flow applications.

Models generated under this approach are, the researchers believe, much more accurate representations of the subject system. It became evident working with the 2009 model that the 2005 Hobby system models had unintended loops within some circuits; these are no longer present. As before, all of the islands in the model are known, and each can be resolved if the researchers choose to do so. In general, the researchers resolve islands only when they would orphan loads, capacitors, or generators (in other words, when they would affect power flow results). Consequently, the researchers now track and maintain over 750 islands. These are mostly one- and two-bus islands. Approximately 700 of these islands are newly discovered since the 2005 models. There are also 135 individual line segments that the researchers have added to the model to correctly connect portions of circuits that would otherwise be islanded. As before, the researchers are able to confirm that just as there are no unintended islands, there are also no spurious ties between circuits.

The 2009 Hobby updates were completed using an enhanced, 150,000-bus version of PSLF provided for this project's use by GE Energy under a subcontract within this project. One of the benefits of the closer integration of the Energynet® model-building software and PSLF is that the researchers are able to determine with absolute certainty that the loads and resources in the dataset are interpreted by the power flow software as the researchers intend. Interpretation differences arising from unintended differences in units, orders of magnitude, and signs emerge, as well as minor errors in PSLF documentation and even very subtle details like whether one of the nearly 1,000 capacitors in the system operates as a discrete or continuous device.

Probably the most important aspect of the matured process is the absence of human steps. In model containing this many different pieces of data, the researchers have found errors are nearly always traced back to a point where a careful but fallible human generated some of the data. The researchers have automated most of these steps, including the many steps involving judgment to address inconsistencies or missing elements in the source data. Therefore, the researchers implement the steps always exactly the same way, and as the researchers find errors, the researchers can ensure they do not occur again.

Ultimately, the researchers feel the approaches to the model development demonstrated here have been very successful in accomplishing the project goals and demonstrating the feasibility and practicality of the Energynet® method. The researchers ultimately developed system models representing three different SCE planning areas and fully integrated them into a westwide transmission model. The first, Hobby, includes nearly 60 substations, 250 circuits, and nearly 50,000 customer service transformers. The second, Mountain, includes over 80 substations, nearly 200 circuits, and over 42,000 customer service transformers. The third, a portion of an unnamed system, included one substation, three circuits, and 792 customer service transformers.

With the implementation of the system data bridges to support the field verification studies the researchers have completed numerous updates of the Hobby system model; these generally take a few days or less.

In the case of the Hobby system the researchers have produced from different source data 15 separate models (so far), 7 reflecting the system on different "system dates," and 8 reflecting different possible future configurations. All have been verified as having no unintended islands or inter-circuit ties. All but a few interim cases are populated with loads derived from actual SCADA records for a variety of conditions or forecasts and represent fully solved power flow simulations.

The researchers believe these are the only examples of the successful development of integrated T&D power flow models of this scale from repurposed utility equipment and system data.

3.1.3. 2011 Forecast Model

The SCE capital budget and project plan also includes a substation-level load forecast stated in total amps under "normal projected" conditions for 2011. Imposing this load growth on the Hobby system without changes provides a second indication, apart from the capital plan itself, of the system's expected operational requirements, and a platform for assessing possible network enhancement measures relative to anticipated loads and system stresses.

The Energynet® model includes real and reactive loads at the distribution customer transformer level derived from actual system data. To develop a load forecast for use in an Energynet® simulation, the researchers converted the SCE substation-level forecasts to MVA using the nominal voltage of each substation, and aggregated the loads of a particular "present" Energynet® case to substation-level MVA. The researchers then applied the substation load growth implied in the forecast relative to the "present" case substation-level loads to each load served by the substation.

This adapted load forecast thus preserves the distribution of loads and their power factor within each circuit and among circuits of a substation that the researchers see in the "present" case system loads developed from SCADA archives. However, it is not a true circuit-level or sub-circuit level load forecast such as might be possible through the application of highly granular spatial load forecasting techniques.[20] The forecast the researchers produced results in a total load for the Hobby system in 2011 of 1,707.3 MW and 628.6 MVAR, or the equivalent of 1,819 MVA. SCE confirmed that their plan's estimate for the 2011 normal projected load for the Hobby system is 1,879 MVA, so as the researchers imposed circuit-level power factors and load distributions, the load forecast the researchers used remains consistent with SCE's plan.

The researchers used this load forecast with a variant of the 2009 updated Hobby model to develop the 2011 Hobby simulation.

3.2. Network Performance Improvement

Two of the core research goals of the project were to demonstrate the additional capabilities of the Energynet® methodology beyond idealized placement of DER and to demonstrate the practical value of the methodology to users, specifically the methodology's ability to enhance power network decision-making and problem solving. Section 3.2 and Section 3.3 together fully address these goals. Section 3.2 demonstrates evaluations of a wide range of potential network performance enhancement measures using the methodology. DER placement is included, but there are others, including traditional substation and circuit expansion projects. Section 3.3

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20. J. Romero Aguero, L. Xu, Wang, J., Hong, T., Willis, H.L., Quanta Technology. February 2009. *Improvements in Spatial Load Forecasting Trending Methods for Distribution Planning Using GIS and Enterprise Data.* Conference Proceedings. DistribuTECH 2009 San Diego, California.

extends the evaluation of these measures to how they address specific operational objectives and their economic value.

3.2.1. Initial Assessment

Apart from simply providing an initial assessment of conditions within the subject system, discussed below, the initial power flow solutions, and the process for obtaining these initial solutions, represented an important error-checking step for the underlying network model datasets themselves. The error-checking features of the load-flow component of GRIDfast™ (GRIDfast™ LF) and PSLF provided guidance to refine the algorithms the researchers used to develop the network model datasets to improve results. In a few cases, errors in source data, mainly in the SCADA archives, became apparent only upon examination of power flow results.

In obtaining initial power flow solutions for the 2009 updated Hobby models, the researchers found that the model was extraordinarily sensitive to voltage, particularly when using PSLF as the power flow solution engine. Lower voltage reduces the effectiveness of capacitors as compensating VAR sources, creating a reinforcing cycle that easily leads to a failure to converge due to either high voltage or low voltage. One possible conclusion from this experience is that a diverged power flow case in this methodology is not necessarily “infeasible” in the physical world. A certain conclusion is that if there are any errors or even unreasonable values in the underlying data, one must identify and correct them for the power flow to converge to a solution. The researchers believe power flow features to make solutions easier and more “forgiving” of data errors may actually be a disadvantage in applications that involve heavy model development such as this.

2005 Hobby System

The researchers successfully developed Energynet® datasets integrating the distribution and transmission of the Hobby system with a regional transmission dataset, and solved initial power flows for the resulting system under a range of network operating conditions. All of these simulations reflect the system layout as it stood on a single “system date,” a date in mid-November 2005. The researchers were not able to use GE’s PSLF to solve the 2005 models initially because the number of buses in the dataset exceeded PSLF’s capacity available at that time.

In obtaining initial power flow solutions for the 2005 models, the researchers found that some of the heavily loaded cases were prone to voltage collapse with the initial configuration of substation transformers to maintain nominal voltage. The researchers adjusted the sending voltages of some substation transformers and most voltage regulators with guidance from SCE such that the cases solved in simulation. With these changes the simulated substation voltages also generally matched the actual substation bus voltages read from the SCADA archives.

The loads in each of the conditions modeled were as follows:

- Normal Summer Peak Conditions:
    - Friday 8/05/05 Hour 16
    - 1,223.7 MW, 615.9 MVAR
- Super-Peak Conditions:
    - Thursday 7/21/05 Hour 14
    - 1,344.3 MW, 651.6 MVAR
- Winter Peak Conditions:
    - Tuesday 1/04/05 Hour 18
    - 675.2 MW, 309.8 MVAR
- Minimum Load Conditions:
    - Sunday 1/23/05 Hour 03
    - 336.6 MW, 125.1 MVAR
- Off-peak or Light Load Hour Conditions:
    - Thursday 7/21/05 Hour 04
    - 492.4 MW, 222.4 MVAR

July 21, 2005 was a peak load day in California in which load curtailment was implemented in the Hobby system and there was a Stage 2 emergency declared by the California ISO. However, the researchers verified that the hour from which the researchers selected data for the "super-peak" case was clear of those factors.

The researchers found, as expected, that the system's real and reactive losses were highest during the periods of highest loading. The researchers also found that the distribution system comprised slightly more of the total losses than did the Hobby transmission system. In particular, as the system moves from a normal peak to a super-peak condition, it appears the distribution losses increase at a greater rate. These findings are summarized in Table 9 and Figure 1.

Table 9. Loss summary

Conditions	P Losses (MW)	Q Losses (MVAR)
Summer Peak	56.530	159.606
Super-peak	68.381	194.653
Winter Peak	19.700	52.349
Minimum Load	5.565	12.677
Off Peak	10.660	27.435

The researchers also found that losses are not equally distributed. About 5% of all lines represent 95% of the total system losses. High-loss distribution lines are distributed; nearly every distribution circuit has some line segments in this top 5% of lines responsible for most of the system's electrical losses.

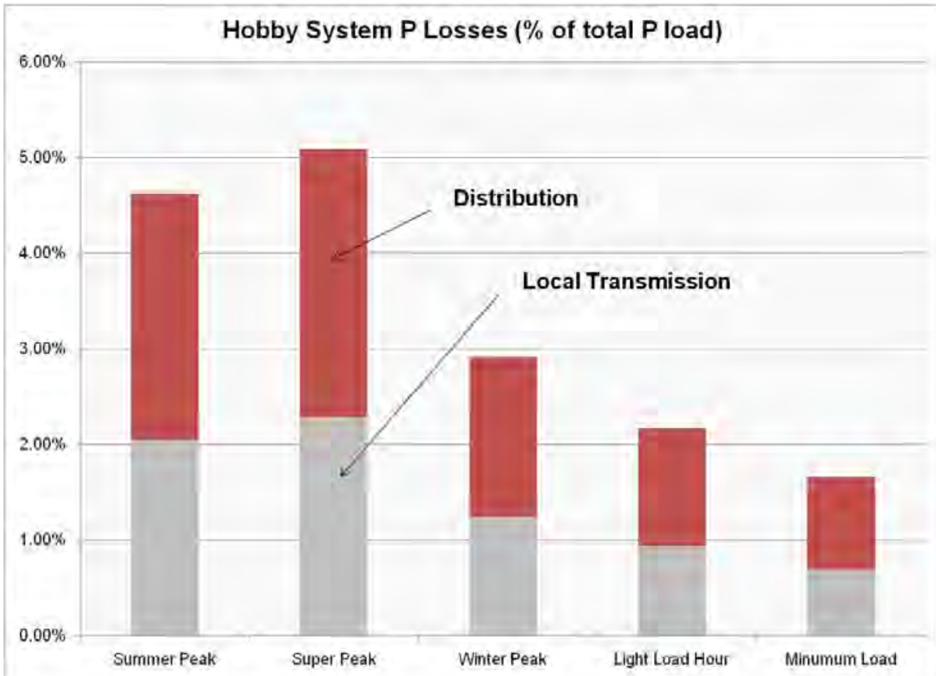

Figure 1. Hobby system loss comparison

As noted above, SCE indicated that in some cases sending voltages in substations will be boosted to compensate for voltage drop on long distribution circuits, a common utility practice. The substation voltages arising from the Energynet® simulation matched fairly closely the actual substation voltages recorded in the SCADA archives, indicating that the voltage "trim" of the Energynet® model matches fairly closely the as-found voltage settings of the system.

The Hobby system with the distribution integrated into a single model reveals far greater voltage variability than the Hobby transmission system alone. In the transmission system the average voltage is relatively close to 1.00 PU (100% of nominal voltage) with little high-low variation or voltage variability. In the distribution portion the average voltages are still relatively close to 1.00 PU, but there is much more high-low variation, particularly in the summer peak and super-peak cases, and more also more voltage variability. Thus, the detailed Energynet® model reveals that a transmission-only look can mask deeper voltage issues in the distribution system. As expected, the more heavily loaded summer peak and super-peak cases reveal more transmission buses with low voltage and distribution circuits with low-voltage buses, and the more lightly loaded winter peak and minimum load cases reveal more high-voltage buses. These findings are summarized in Table 10.

Table 10. Voltage summary

Conditions	Average Voltage (PU)	Vmin (PU)
Summer Peak	1.004	0.811
Super-peak	1.003	0.788
Winter Peak	1.006	0.906
Minimum Load	1.025	0.978
Off Peak	1.021	0.984

The researchers evaluated the system for individual buses with "extreme" voltages outside thresholds of less than 0.95 PU and greater than 1.041 PU. These thresholds are somewhat arbitrarily chosen to reveal true outliers. It is notable that the high-voltage demarcation the researchers used for the summer peak cases was also useful for the winter peak and minimum load conditions. This indicates that SCE's capacitor dispatch routine now in place for the Hobby system fairly effectively adapts to winter and off-peak conditions, maintaining system voltages within a range during those conditions.

One circuit, Peach, has buses with voltages under 0.90 PU under normal summer peak and super-peak conditions – the lowest voltage buses in the system. It is also the only circuit with low-voltage buses under both summer conditions and under winter peak conditions as well. Peach is served from Fruit substation in Hobby North, which is one of the substations with elevated sending voltage, so this low voltage is a sub-circuit phenomenon.

Hobby system capacitor dispatch is very different under minimum load conditions. The researchers found 26 circuits with voltages above the "high" threshold, of which 19 had high-voltage buses only under minimum load conditions. One circuit, Horseshoe, had high-voltage buses under all but summer super-peak conditions.

Another circuit, Appaloosa, has low-voltage buses under both normal summer peak and super-peak conditions, and high-voltage buses under minimum load conditions.

The researchers also evaluated the system for several VAR flow indicators including line segments with heavy loads and real and reactive flow in opposing direction. These findings are not presented in detail here, but generally suggest that reverse reactive power flows and circuits exporting VARs are the result of capacitor placement rather than over-compensation.

Based on SCADA reads the researchers found 13 circuits with current over 550 amps under super-peak conditions, but no circuits with current over 550 amps under the other conditions modeled. However, as shown in Table 11, under every set of conditions the researchers found circuits with individual line segments whose currents exceeded the "normal" rating for their cable specification. This indicates that generalizations regarding appropriate circuit loading may not indicate true overloads.

Table 11. Circuits with individual line segments exceeding normal rating

Conditions	Number of Circuits
Summer Peak	29
Super-peak	39
Winter Peak	15
Minimum Load	7

In the case of each of these circuits, a dozen or fewer line segments were actually flagged as loaded beyond their normal rating. The most likely explanation is that the conductor specification for these lines is incorrect in the source data. Further, these lines, once identified, represent a small group that can be readily checked to confirm their recorded rating.

These could be also legitimate pinch points in the circuit. Figure 2 compares the summer peak loading with the "normal" rating of each line segment on a particular path of the Pear circuit and represents an interesting example. Under summer peak conditions the loading never approaches the 600 amp normal rating prevailing on most of the circuit's lines. The exception is a group of lines whose rating is far lower, less than 200 amps. This circuit would probably not be identified as a heavily loaded circuit based on its summer peak loading at the substation of under 400 amps, yet the simulation reveals that it is nonetheless potentially overloaded.

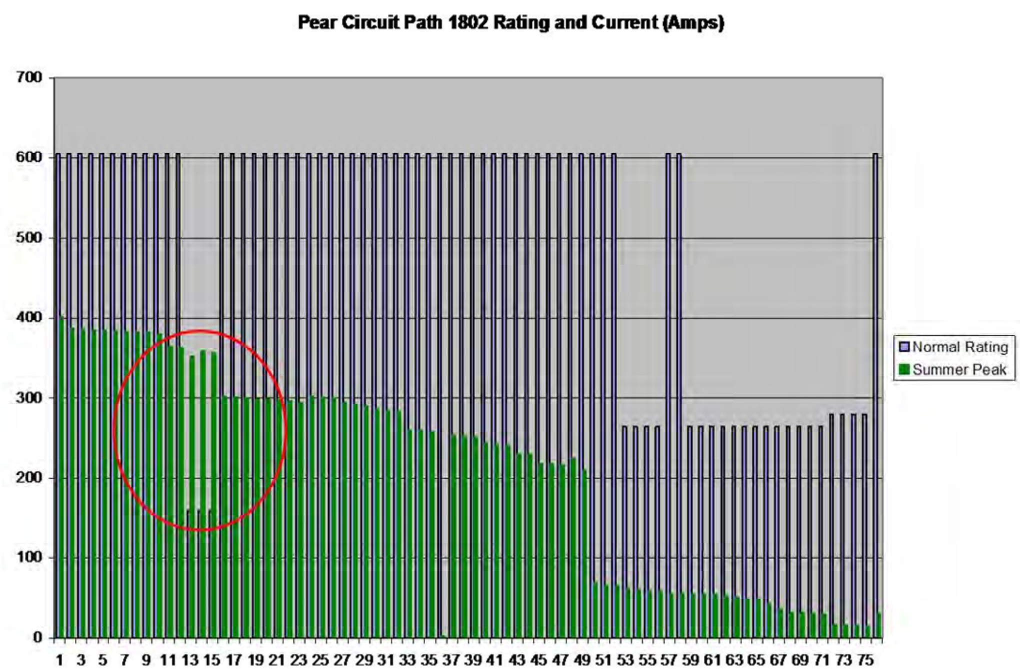

Figure 2. Pear circuit loading profile

2009 Hobby System

The researchers actually performed multiple "2009" updates. Using as an example a case in which the system data was for the Hobby system as it stood on August 3, 2009, and loads, device status, and resources as they were measured on September 10, 2009, at Hour 14[21], the power flow converged in PSLF in two iterations with an estimated solution error of 0.0410 MW and 0.0288 MVAR and an actual mismatch of 0.0 MW and 1.8 MVAR. The sum of all individual modeled loads in the Hobby system was 680 MW and 398 MVAR. The highest and lowest voltages in Hobby within the power flow were 1.06 PU (106 % of nominal) and 0.975 PU (97.5% of nominal), respectively, and the highest and lowest measured voltages in the field were 1.08 PU and 0.96 PU respectively. Losses in the distribution portion of Hobby were calculated in the power flow at 13.44 MW and reactive power consumption at 52.269 MVAR.

If these conditions are at all representative of a normal summer peak, it is evident first of all that compared to the 2005 Hobby model, system loads are much lower and there is far less voltage variation. The voltage variation is likely related to the loads; it may also be related to better functioning of the capacitors, transformer taps, and voltage regulators within the model. In this case the researchers have the ability to compare modeled voltages with field-read voltages, and the researchers have greater confidence that the modeled voltages are correct.

The Hobby system as it stood on September 10, 2009, with September 10, 2009, Hour 20 loads has:

Systemwide Losses:	40.6083 MW	112.0094 MVAR.
Systemwide Minimum Voltage:	0.9420 PU,	

and there are 2 circuits with buses with voltage under 0.95 PU.

These values are from the GRIDfast™ LF power flow, with losses determined by summing the losses from individual local transmission, substation, and distribution line segments. For comparison purposes, the results from the PSLF power flow indicated:

Systemwide Losses:	41.1187 MW	102.5927 MVAR.
Systemwide Minimum Voltage:	0.9345 PU,	

In each solution the systemwide minimum voltage occurs at the same individual bus in Towhee circuit.

These results show that on a direct comparison basis over nearly 100,000 individual line segments the GRIDfast™ power flow results for losses are very nearly identical to the results from PSLF, which was used for the validations.

21. The "hour" values for the 2009 cases is a nominal value taken from the field instrumentation archives.

2011 Hobby System

To characterize the Hobby system under forecast loads but without any changes, the researchers began with a simulation reflecting the system as it stood on September 10, 2009. Using the GRIDfast™ power flow the researchers found the following conditions under forecast loads:

Systemwide Losses:	97.4674 MW	282.8681 MVAR.
Systemwide Minimum Voltage:	0.8987 PU	

Thus with these forecast loads and no additions or modifications to the system from its state on September 10, 2009, or any of the load shifts SCE has identified in the Hobby system capital plan, the system is very heavily loaded. At .899 PU or 89.9% of nominal at the lowest point, there are quite low voltages. There are eight circuits with one or more buses below 0.95 PU.

In the 2011 Hobby Energynet® simulation the researchers found 15 substations with actual sustained overloads – that is, that exceed their normal ratings when serving forecast loads. Arguably these substations require relief, or added effective capacity, through load shifts or additional transformation capacity. These include the following:

- Oyster 12 kV
- Fish 12 kV
- Limpet P.T.
- Metal 12 kV
- Bobwhite P.T.
- Preventer 33/12 kV
- Boat 115/12 kV
- Weckl 12 kV
- Sail 115/33 kV
- Hawser 33/12 kV
- Music 115/12 kV
- Paint 115/12 kV
- Author 12 kV
- Bird 115/33 kV
- Heron 12 kV

The eight circuits with low voltage identified in the 2011 Hobby model lie in the systems listed below.

- Sail 33 kV
- Fruit 12 kV
- Horse 12 kV

- Wildcat 33 kV
- Modjazz 33 kV
- Bird 33 kV

3.2.2. Reliability Assessment

2005 Hobby System

As stated above, the researchers evaluated the "baseline" reliability of the subject system in the context of two contingencies: a) an outage of a single transformer bank in a distribution substation and b) a single distribution circuit line outage that would affect all of the load served by the circuit.

The researchers established "base" contingency probabilities of ten hours per year of line outages and ½ hour per year of substation transformer outages for each circuit per 100 circuit miles. Thus, under the researchers' assumptions, each circuit has its own set of contingency probability values. To take loading into account, the researchers applied a 10% adder to the base contingency probability of circuits whose most heavily loaded element was loaded at 120% of the normal rating or greater. This adder is predicated upon the relationship between circuit loading and failure rate posited by NCI and discussed in more detail in Section 2.2.2.

In outage frequency and duration terms, for a circuit in the Hobby system having average length and not unusually heavily loaded, these assumptions translated to 1.8 hours per year of line contingency and 0.09 hours per year of transformer contingency.

The researchers' evaluation of the topology and loading of the system showed that there are large differences among circuits in terms of their ability to respond to these contingencies and avoid unserved customer load ("interruptions"). Each individual circuit has different opportunities to shift load to adjacent circuits, ranging from none to many. Further, the loading on each system element relative to its normal and emergency ratings, and thus the ability to accept additional load under contingency conditions, varies across super-peak to normal summer peak or winter peak and off-peak conditions. To capture this, the researchers imposed a distinction between "outages" or contingencies and "interruptions."

The researchers identified those substations in the subject system with single transformer banks; that is, where the loss of a transformer bank would require load redistribution (if possible) to avoid unserved load. Of the Hobby substations, approximately 25 are single-bank substations. Most of these are pole-top substations.

The researchers also identified those substations where the loss of the single largest transformer bank (an N-1 condition) would result in loads exceeding the total emergency rating of the remaining bank(s), also requiring load redistribution (if possible) to avoid unserved load. This is a time- or operating condition-specific determination; the researchers found 15 substations with this condition under summer peak conditions, 19 under super-peak conditions, and one under winter peak conditions. As a corollary, the researchers considered circuits served from a substation with multiple banks and with adequate capacity to its aggregate load under all conditions within transformer emergency ratings and the loss of the single largest bank as not at risk for unserved load due to a transformer bank contingency.

The researchers then used the model to examine each of the Hobby circuits for its opportunities to shift load to "sibling" circuits to which it is connected by inter-circuit ties. Most Hobby circuits have ties to multiple "sibling" circuits. The researchers assumed that in general each circuit should have two backups or alternate feeds in addition to its primary source. The researchers understand that this is SCE's design practice. Separately, Willis suggests a 3-zone design for electric distribution, effectively permitting a 1/3 portion of a circuit to be served from one of three different sources, as a way to reduce the need for carrying excess capacity in circuits while also allowing the shift of a circuit's loads in a reasonable number of switching steps. [22] Further, networking studies by Paul Barand in the formative days of the Internet showed that a primary connection plus as little as two levels of redundancy for each node in a network approaches the theoretical limit of robustness.[23]

The researchers evaluated the loading of individual circuits for their capability to serve as alternate feeds following a contingency. The researchers found a total of 60, 43, and 13 circuits within the Hobby system that had loading at 65% or more of their most restrictive emergency rating under super-peak, summer peak, and winter peak conditions, respectively. This assessment was based on the engineering ratings of the individual circuit components and the loading on those elements from power flow solutions for each case. The researchers judged these circuits to be ineligible to accept a significant share (say a third) of a "sibling" circuit following a fault under those operating conditions.

Returning to the transformer outage contingency, for those substations loaded beyond their emergency ratings under N-1 conditions the researchers used the Energynet® simulation to make an assessment of the opportunities to shift load to other substations using circuit tie switching. The researchers determined the total number of ties among the substation's circuits that connected to other substations' circuits. The researchers then assessed the number of such ties with the capacity to accept a load shift as above. Under this rubric the researchers judged that it would take three acceptable destination circuits to accept the equivalent load of one entire circuit of a given substation; if the researchers found sufficient destination circuit capacity the researchers considered that substation as not at risk for unserved load resulting from a transformer bank outage. If the researchers did not find sufficient destination circuits, the researchers assumed shares of some circuit(s) would go unserved, but spread that risk across all the individual circuits of the substation.

For the line outage contingency, the researchers found that some circuits lack any ties to "sibling" circuits that can serve as alternate feeds. The researchers viewed these circuits fully at

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22. H. Lee Willis. 2004. *Power Distribution Planning Reference Book*. CRC Press, New York.

23. Hafner, Katie and Matthew Lyon. 1996. *Where Wizards Stay Up Late – The Origins of the Internet*. Simon & Shuster, New York. p 59.

risk for unserved load due to a line outage requiring a load shift. There are 10 such circuits in the Hobby system.

For those circuits with alternate feeds, the researchers evaluated the nature of the connections between circuits and their backups. The researchers viewed circuits with no automated or remotely operable switches to backups as partially at risk for unserved load due to a line outage requiring a load shift, as post-contingency load transfers are available, but not immediately. As indicated above, the researchers viewed circuits with automatic or remotely operable alternate feeds as at no risk for unserved load in the event of such a contingency.

The researchers then evaluated the reliability impact of loaded sibling circuits described above on the post-contingency load-shifting opportunities of the circuits they back up. The researchers considered any circuit where loaded backup circuits reduced opportunities to shift load to an alternate feed either; a) by more than half, or b) to fewer than two, as "at risk" for unserved load under a line contingency where a load shift would be required. The researchers found 41 such circuits under super-peak conditions, 31 under summer peak conditions, and 10 under winter peak conditions.

Taking all of these factors together permits the authors to characterize the ability of each individual circuit to mitigate the impact of the random transformer and line contingencies the researchers first postulated under each set of operating conditions. So, under these assumptions, a circuit served from a substation with both adequate reserve transformer capacity in the substation and adequate alternate feeds would experience no interruptions due to the contingencies the researchers postulated. At the other extreme, for a circuit with no reserve substation transformer capacity and no alternate feeds, the postulated random contingencies would always result in actual customer interruptions. These assessments are also time and condition specific. A circuit with compromised reliability due to limited substation transformer capacity or alternate feeds under both summer peak and winter peak conditions would be at greater risk of customer interruptions than a circuit with compromised reliability only under super-peak conditions.

As a last consideration, the researchers incorporated the combined outage exposure to transformer and line outages of each circuit serving loop-fed substations. Essentially, a parent circuit outage is like a transformer bank outage to the child circuits of the loop-fed substation, and subject to the same risks and mitigates.

The average risk-adjusted interruption rate over all circuits in the 2005 Hobby system that results from this analysis is 0.61 hours (37 minutes) per year. This compares well with a "typical" system SAIDI value of one hour per year [24], indicating that the random outage values and subsequent treatment the researchers used are reasonable, and may be slightly conservative.

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24. Roger C. Duggan. *Electrical Power Systems Quality*.

However, what matters more than the overall average outage rate for the system as a whole is the difference among the system's individual circuits. Figure 3 shows the distribution of interruption risk for the 215 circuits in the 2005 Hobby system, and makes it very clear that the vulnerability of these circuits is not evenly distributed. There is a small number (around 11 circuits) with extraordinary interruption risk, and a large number (around 57) with nominally zero interruption risk. In this system a risk-adjusted expected circuit outage rate of 1.5 hours per year or higher is unusual. The 10 circuits with the highest outage risk are Apple, Peach, Orange, and Grapefruit out of the Fruit substation, Starfish and Tang out of the Fish 12 kV substation, and Violin, Hubbard, Shovel, and Spruce circuits, each out of separate substations.

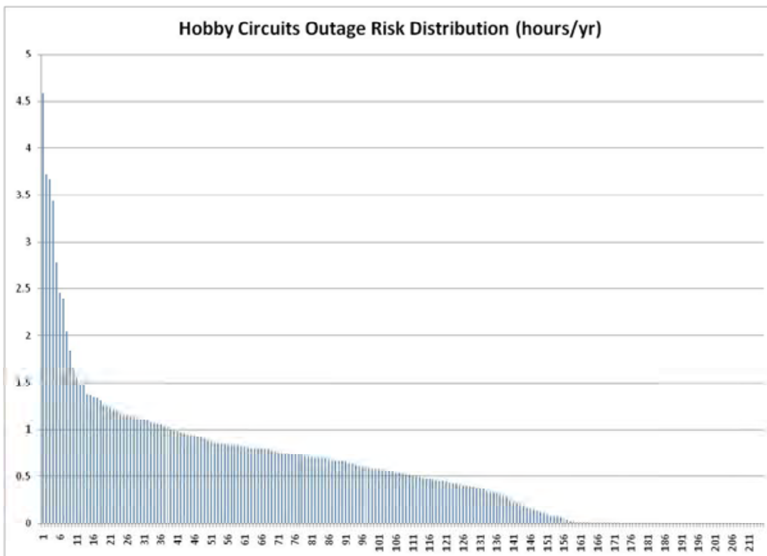

Figure 3. Outage risk distribution of individual Hobby circuits

Table 12 illustrates the combination of factors that result in a circuit's higher-than-average outage risk. Because each circuit's "base" contingency risk is partially a function of its length, very long circuits in the Hobby system tend to show higher individual circuit outage risk. Four of these long circuits are also served from a single substation having elevated risk of unserved load due to a transformer contingency. Several of these circuits have constrained post-contingency load shift opportunities due to loading of alternate feeds. Where this is the case under both winter peak and summer peak conditions, the contribution to posited outage risk over the course of the year can be significant. Two circuits have load at risk under a transformer contingency event, which is compounded by the outage risk of their substations' parent circuits.

Table 12. Contributing factors of high-outage-risk circuits

Circuit Name	Circuit Length	Transfer Risk	Loaded Alternative Feeds	Parent Circuit Risk
Starfish	X		X	
Apple	X	X	X	
Violin	X			
Peach	X	X		
Tang	X		X	
Orange	X	X		
Grapefruit	X	X	X	
Parrot		X		X
Jib		X	None	X
Hubbard	X		X	
Garden			X	

The distribution of the outage risks of Hobby circuits expressed in terms of unserved energy (kWh/year) is similar; there are about 10 circuits with disproportionately high risk. These circuits are largely the same group, which is reasonable given a relationship between circuit length and served load. A new circuit, Towel, emerges in this sorting. Towel is very heavily loaded and has constrained backups.

Because the researchers know the makeup of the affected customers on each circuit, the researchers can also state the outage risks of individual circuits in terms of the total value of unserved energy (value of service, or VOS). The researchers acknowledge first that this type of analysis is wholly dependent upon the assumptions used for the value of unserved load of certain customer groups. The researchers also acknowledge that the "value of unserved energy" does not necessarily mean the financial value to the utility of avoiding a given outage or the value a customer would be willing to pay to avoid the outage. The values the researchers used to assess the value of unserved load are listed in Section 2.3.1.

There are 10 circuits in Hobby with disproportionately high circuit outage risk in terms of VOS. Of these, Starfish, Apple, Grapefruit, Violin, Orange, and Tang have been seen before by the researchers as long, heavily loaded, and exposed to high outage risks due to the characteristics of the system. In addition to these, Redman, Melville, and Ketch emerge due to their outage risk affecting high-value loads. Melville and Ketch loads are at risk due to loaded alternate feeds, and Redman loads are at risk under a transformer contingency event and also due to all-manual connections to alternate feeds.

In light of the impact of circuit loading on "sibling" circuits' post-contingency load shift opportunities and, in turn, those circuits' expected interruption rate, it is revealing to turn the results around to consider the circuits having this effect. Thus, the researchers considered those circuits with loading at greater than 65% of their emergency rating *and* that served as an alternate feed for a "sibling" circuit with less-than-desirable load shift opportunities as described above. There are 52 circuits whose loading places one or more "sibling" circuits at greater interruption risk due to insufficient post-contingency load shift opportunities, according to this project's reliability rubric. Most of these affect one or two circuits. However, there is one, Wrasse, which affects five other circuits in this way, and two that affect four and three circuits – Starfish and Platty, respectively.

Interestingly, the assumption of increased failure risk of individual loaded line segments did not seem to be a major factor in distinguishing the high-risk circuits from the others. Similarly, the absence of automated switching did not seem be a factor other than with Redman when combined with high value-of-service loads. In other words, according to these results, the unavailability of load shift opportunities is a far larger factor in high reliability risk circuits than is loading within that circuit or automated transfer switching.

2011 Hobby System

The researchers also performed a reliability assessment following this approach for the 2011 Hobby system with forecast loads and no system changes. As explained below, this reveals where in the system the combined impacts of substation and circuit loading and topology result in much higher theoretical risk for unserved load from expected, random contingencies. This, in turn, reveals those substations and circuit overloads in the Hobby system that, if mitigated, would yield the greatest reliability benefit.

The researchers assumed the same base contingency probabilities for each circuit and substation based on circuit length, with the same added factor for line loading. The researchers considered the topology and loading of the system to determine the potential for unserved load due to either a transformer bank outage or a line outage. Again, this assessment takes into account the ability of substations to continue to serve their loads with remaining banks in service and the opportunities to shift loads to sibling circuits that have sufficient capacity. With the heavier forecast loads, the availability of both of these remedial actions is reduced. Working with a single forecast case, the researchers did not have the ability to assess how these factors differ under summer or winter operating conditions or peak or off-peak operating conditions.

The researchers found 31 single-bank substations and another 24 substations whose loading under forecast loads would exceed the total emergency capacity with the largest bank out of service. In other words, under forecast loads, all but one Hobby substation would have to shift or curtail load in the event of an outage of its largest transformer bank.

The researchers found 98 circuits in the Hobby system under forecast loads with one or more segments loaded at over 65% of its emergency rating and 32 circuits with one or more segments loaded at over 120% of its normal rating. Of 246 circuits in this variant of the Hobby system, 229 have alternate feeds via inter-circuit ties in this configuration, and 17 do not. Of the 229 circuits, the researchers found that 120 have less than the desired load shift opportunities due to loading of sibling circuits.

The individual substations whose circuits bear the greatest risk of unserved load in the event of a transformer bank outage, based on both reserve bank capacity and the ability to shift load to alternate feeds, are the following:

- Bobwhite (Bird system)
- Macaw (Bird system)
- Owl (Bird system)
- Starboard (Sail system)
- Preventer (Sail system)
- Heron (Heron system)
- Cockle (Shellfish system)
- Fruit (Fruit system)
- Ornette (Modjazz system)
- Garden (Garden system)
- Flower (Flower system)

The individual circuits with the greatest risk of unserved load in the event of a line outage, due primarily to the limited ability to shift load to alternate feeds, are the following:

- Jaguar (Wildcat system)
- Clam (Shellfish system)
- Crow (Bird system)
- Peach (Fruit system)
- Carter (Modjazz system)
- Violin (Music system)
- Brecker (Modjazz system)
- Spruce (Tree system)

The researchers took all these factors together, along with the outage exposure of the circuits served from loop-fed substations to outages of their "parent" circuits, to characterize the aggregate ability of each individual circuit to mitigate the impact of transformer bank and line contingencies having random probabilities.

The distribution of outage risks among the Hobby circuits is shown below in Figure 4. This is very similar in shape to the distribution of circuit outage risks the researchers found for the 2005 Hobby, shown above. The "hours per year" outage risk values are nominally higher for the 2011 Hobby system because with a single case the researchers essentially consider the peak conditions of the forecast case as prevailing through the year. The 10 circuits with the highest outage risk are Jaguar, Clam, Jay, Brecker, Peach, Carter, Violin, Rode, Spruce, and Persian. Each of these is served out of a different substation.

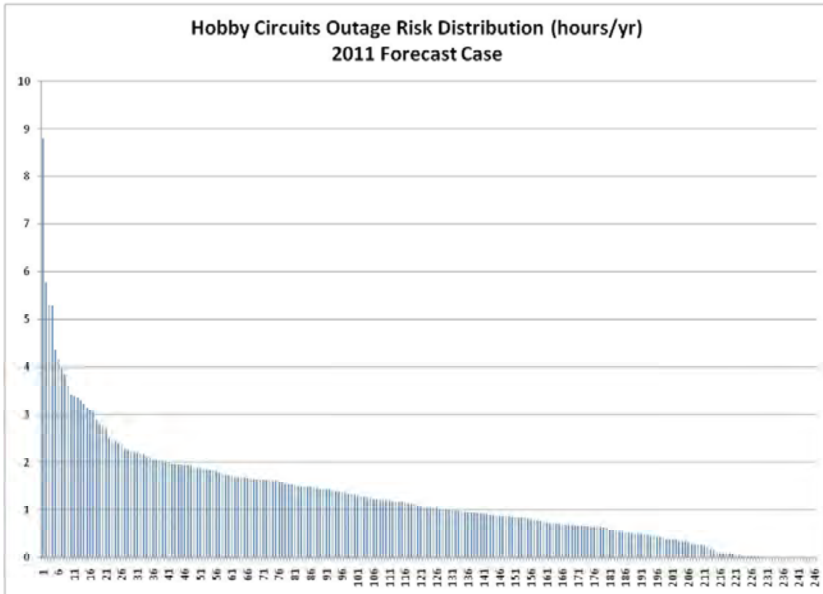

Figure 4. Outage risk distribution of individual Hobby circuits

Table 13 illustrates the combination of the factors that result in these 10 circuits' higher-than-average outage risk. It appears that transformer outages and loaded alternate feeds are a more common factor than circuit length when compared to the high-risk circuits in the 2005 Hobby system. This is certainly the result of higher loads in the forecast case, and possibly due to some circuit redistribution that has occurred in the Hobby system during the intervening years.

Table 13. Contributing factors of high-outage-risk circuits

Circuit Name	Ckt Length	Xfr Risk	Loaded/Limited Alt Feeds	Parent Ckt Risk
Jaguar	X	X	X	
Clam		X	X	X
Jay		X	X	X
Brecker		X	X	X
Peach	X	X		
Carter	X			
Violin	X			
Rode		X	X	X
Spruce			X	
Persian		X	X	X

This list does not necessarily suggest that the 2011 Hobby system has reliability needs *per se*, but it does suggest some matters that if addressed would improve the standing of portions of the system that have much greater-than-average theoretical reliability risk.

3.2.3. Recontrols

2005 Hobby System

The recontrolled cases reflect a large number of operational changes from the “as found” system configuration. The overall impacts of these changes are summarized in Table 14.

Table 14. Impacts of recontrols – 2005 Hobby System

Hobby System	Operating Conditions	Vmin Improvement (PU)	P Loss Reduction (MW)
November, 2005	Summer Peak	0.047	3.239
“	Winter Peak	0.046	1.304
“	Super-peak	0.036	2.445
“	Off Peak	-0.007	0.435
“	Minimum Load	0.006	0.340

Under summer peak conditions, of 787 distribution line capacitors in the 2005 Hobby system, 219, or about 28%, were re-dispatched in the recontrol step relative to their as-found status taken from the SCADA records for each case. Under super-peak conditions, 182 were redispatched, and under winter peak conditions, 264 were redispatched. Note that, as stated above, the researchers assumed that all capacitors installed in the Hobby system are commissioned and available. In reality, some share of these would not be operational, and the capacitor inventory is designed accordingly. There were also changes to the transformer tap settings and the VAR output of existing distributed generation units.

Under super-peak conditions, these changes eliminated the buses with voltages less than 0.95 PU under super-peak conditions in the Pear, Apple, and Orange circuits of the Fruit subsystem, the Blanket and Spur circuits of the Ride subsystem, the Ketch circuit of the Boat 12 kV subsystem, the Appaloosa and Tobiano circuits of the Horse 12 kV subsystem, the Elm, Cedar, and Oak circuits of the Tree 12 kV subsystem, the Eagle circuit of the Bird 33 kV subsystem, the Jaguar circuit of the Wildcat subsystem, and the Nickel circuit of the Metal subsystem.

Under winter peak conditions, these changes eliminated the buses with voltages less than 0.95 PU all circuits (a total of nine circuits in the Fruit, Sail 33 kV, Tree 12 kV, Bird 33 kV, Dog, and Wildcat 33kV subsystems).

Capacitor Automation and Distributed Generation Automation

These “recontrol” results specify the device operating status of each of the Hobby system’s 839 existing substation and distribution line capacitors under a range of operating conditions when dispatched according to the GRIDfast™ algorithm to minimize real and reactive losses and voltage deviation, the formal optimization objective used in these studies. These results are summarized in Table 15.

Table 15. Ideal operating profiles of Hobby capacitors

Profile	Number of Capacitors
Variable	559
Always ON on peak and OFF off peak	139
Always ON	56
Always OFF	85

The "optimal" operating profile of each capacitor then implies a set of control requirements. For example, a capacitor whose ideal operating profile indicates that its ON or OFF status should change under different operating conditions can more easily provide that profile as part of a sophisticated control scheme capable of delivering remote dispatch instructions informed by ongoing system monitoring. On the other hand, a capacitor whose ideal profile is "always ON" can provide that profile without sophisticated remote controls.

The researchers found that ideal dispatch profiles of the Hobby capacitors do in fact place them in different control scheme categories. The device status of the 524 capacitors with a "variable" operating profile should ideally change under different system conditions, thus the system would benefit if these were placed under a control scheme with direct system condition input. The device status of 139 of the capacitors also should change, but much more predictably – they should always be ON during peak conditions, both summer and winter, and OFF at night. Therefore, the system's needs might be adequately served if these individual capacitors were simply timer-operated. The ideal dispatch profile of the remaining 141 capacitors does not change under the conditions the researchers evaluated, thus these could serve the system's needs as "fixed" capacitors.

The potential benefits of a capacitor control system that can optimally dispatch system capacitors based on system conditions and redispatch those capacitors as system conditions change are significant. The recontrol benefits shown in Table 14 reflect the impact of ideal settings of transformer taps and the VAR output of synchronous distributed generation as well as ideal capacitor settings. The majority of this impact is attributable to capacitor dispatch.

Of the existing embedded power generation within the Hobby system, the researchers modeled 13 as having synchronous generators and the capability to produce or consume reactive power within normal generator limits. The researchers also made this reactive power resource available as a "recontrol" component.

The recontrol results in Table 14 reflect the VAR output of these synchronous devices under ideal dispatch and varying system conditions. The researchers found that with very few exceptions these resources are optimally dispatched at a power factor other than unity, and that their ideal power factor changes as system operating conditions change. This suggests that reactive power capability of these generators is a valuable resource that could be made available to the network operator, and that given its variability, would be more valuable under a distribution automation scheme in which dispatch instructions can be derived from actual system conditions and delivered remotely. The actual benefits performance of such a scheme involving these 13 generators is difficult to see, as they are such a small part of the system.

2009 Hobby System

Performing an optimization of the September 10, 2009, Hour 20 Hobby system's transformer taps, capacitor dispatch, and VAR output of existing distribution-connected using GRIDfast™ , the researchers found the following for the Hobby system under those conditions:

Systemwide Losses:	39.2256 MW	108.6520 MVAR
Systemwide Minimum Voltage:	0.9865 PU	

Therefore, the recontrols using GRIDfast™ would reduce losses and improve the systemwide minimum voltage to where there are no buses with voltage lower than 0.95 PU.

Under this optimized condition, the Hobby system's voltages are all within the ideal range, and a P Index more negative than the average less two standard deviations is only -2.7. Therefore, it is reasonable to expect that small changes in resources, even in locations with relatively extreme resource deficiency or surplus, would have a very small effect on observable conditions such as voltage.

2011 Hobby System

The researchers performed an optimization of the 2011 forecast case incorporating redispatch of the Hobby system's existing transformer taps, capacitors, and the VAR output of existing distribution-connected yielded the following results:

Systemwide Losses:	93.5511 MW	272.8756 MVAR.
Systemwide Minimum Voltage:	0.9300	

This set of results reflects making the best use of existing resources within the system, thus the researchers use this configuration as the starting point for evaluating potential network improvement measures.

Since the researchers do not know how the forecast case would have been configured otherwise, there is not a rigorous way to assess the impact on the 2011 forecast case of recontrols alone as a standalone measure. For purposes of comparing recontrols with other network measures in the 2011 Hobby system, the researchers will use the values the researchers found for the September 10, 2009, recontrol results for the forecast case, as indicated in Table 16.

The 2011 forecast case with ideal control settings does show that voltage-related objectives of the Hobby system as revealed by its performance under forecast loads can be largely addressed with existing resources. With optimized controls, the number of circuits with low-voltage buses is reduced to one, Saddlebred circuit in the Horse system. Accordingly, low-voltage issues noted in the Hobby capital plan in Sail 33 kV, Fruit 12 kV, Wildcat 33 kV, Modjazz 33 kV, and Bird 33 kV systems would be resolved through ideal control settings.

Table 16. Impacts of recontrols – 2009 and 2011 Hobby System

Hobby System	Operating Conditions	V min Improvement (PU)	P Loss Reduction (MW)
September 2009	Summer Peak	0.026	1.383
2011 Forecast	Summer Peak	0.026	1.383

3.2.4. Redispatch of Existing DER

Demand Response

The Hobby system has a large number of existing demand response resources. The researchers assumed that existing demand projects available under super-peak conditions; and analysis showed that coordinated dispatch of certain highly ranked projects in this group could have quantifiable voltage and loss benefits.

For the 2005 Hobby system, the researchers ranked 4,684 of the existing demand response projects in terms of their network benefits under super-peak conditions. These projects comprise 15.11 MW in total, or an average size of 3 kW, and lie on nearly every Hobby circuit (189 of 215). If dispatched as a group, the existing demand response projects increase the systemwide minimum voltage from 0.8977 PU to 0.905 PU, an increase of 0.7 percentage points and reduce systemwide P losses from 67.095 MW to 65.789 MW, a reduction of 1.306 MW. They also increase the systemwide median voltage from 1.0088 to 1.0090, reduce voltage variability from 0.0195 to 0.0191 and reduce the number of buses under 0.95 PU by 125, from 1,088 to 963.

Among the existing demand response projects, the 125 highest-ranked in terms of network benefits have the most significant impact on systemwide minimum voltage under super-peak conditions, raising it from 0.8977 to 0.902 PU. They also increase the system's median voltage from 1.0088 to 1.00894, reduce the voltage variability from 0.0195 to 0.0193, and reduce the number of low-voltage buses by 67, from 1,088 to 1,021. These 125 existing demand response projects lie on 11 circuits, further, 75% of the capacity represented by these projects is on just four circuits -- Wrasse, Peach, Carter, and Towel. The next 875 highest-ranked existing demand response projects also yield meaningful voltage benefits. They increase the systemwide minimum voltage from 0.902 PU to 0.905 PU. They also increase the system's median voltage from 1.00894 to 1.0090, reduce the voltage variability from 0.0193 to 0.0191, and reduce the number of low-voltage buses by 57, from 1,021 to 964.

The remaining 3,684 existing demand response projects have very modest voltage benefits.

Distribution Automation – Enhanced Demand Response Automation

The high-value existing demand response resources noted above could yield the related system performance benefits more effectively through the application of individual device level or circuit level dispatch, particularly where dispatch can be initiated for local system conditions rather than say statewide electrical capacity deficiency.

The top 125 existing demand response projects identified above lie on eleven circuits altogether, and in fact, most of their capacity is on just four circuits – Wrasse, Peach, Carter, and Towel. Therefore, providing or enabling device-level dispatch in these examples is a confined, definable task. In light of the demonstrated value of these resources, there may also be an argument for closer monitoring to assess their availability and their performance when called. If a nominally high-value demand response resource were typically not responsive due to an equipment or communication malfunction, it would reasonably take on a higher priority for attention.

Distributed Generation

Table 17 lists the existing distribution-connected generation projects in the Hobby system that the researchers modeled as having defined operating profiles. Of these, 11 have synchronous generators and the capability to produce or consume reactive power within normal generator limits. The researchers made these reactive power resources available as "recontrol" components, and the recontrol results presented above for both the 2005 Hobby system and the 2011 Hobby system reflect ideal dispatch of the VAR output of these resources.

Table 17. Hobby system existing distribution-connected generation projects

Circuit Name	Substation Name	Operating Profile	Pmax (kW)	Qmax (kVAR)	Qmin (kVAR)
Lionfish	Fish 115/12 (D)	Cogen	60.0	30.0	-20.0
Iris	Flower 115/12 (D)	Cogen	60.0	30.0	-20.0
Copper	Metal 115/12 (D)	Cogen	60.0	30.0	-20.0
Thoroughbred	Horse 115/12 (D)	Cogen	300.0	150.0	-100.0
Loon	Bird 115/33 (D)	Cogen	1,100.0	550.0	-366.7
Plow	Garden 115/12 (D)	Cogen	2,000.0	1,000.0	-666.7
Barbera	Grape 115/12 (D)	Cogen	4,070.0	2,035.0	-1,356.7
Halter	Ride 115/12 (D)	Hydro	650.0	325.0	-216.7
Ellis	Modjazz 115/33 (D)	Hydro	7,900.0	3,950.0	-2,633.3
Watercolor	Paint 115/12 (D)	PS	334.0	167.0	-111.3
Cedar	Tree 115/12 (D)	PS	360.0	180.0	-120.0
Parrot	Sandpiper P.T. 33/12 (A)	Solar	5.6	-	-
Blanket	Ride 115/12 (D)	Solar	29.8	-	-
Drum	Music 115/12 (D)	Solar	29.8	-	-
Pear	Fruit 115/12 (D)	Solar	36.0	-	-
Manganese	Metal 115/12 (D)	Solar	36.0	-	-
Drum	Music 115/12 (D)	Solar	38.6	-	-
Sandberg	Author 115/12 (D)	Solar	39.9	-	-
Marconi	Starboard 33/12 (D)	Solar	42.7	-	-
Horseshoe	Ride 115/12 (D)	Solar	52.8	-	-
Sachmo	Jazz 115/12 (D)	Solar	58.4	-	-
Goldfish	Fish 115/12 (D)	Solar	58.4	-	-
Oak	Tree 115/12 (D)	Solar	623.0	-	-

In terms of real power output, the Cogen, Hydro, and PS (Peak Shaving) resources listed in the table are dispatchable. As a default, the researchers assumed that these projects were available and operating during peak (daytime) periods, and in the case of the Cogen resources, available and operating during off-peak periods. The Solar projects are not dispatchable, and the researchers assumed as a default that they are available and operating during peak periods.

The researchers evaluated each project and determined that at each project site real capacity at that location under the 2005 Hobby system conditions is on balance beneficial to the system's performance. Therefore, with all dispatchable projects operating during peak periods, there is no benefit to network performance from turning any of these resources down or off. Thus, the researchers conclude that as a network performance improvement measure there is no incremental benefit available from redispatch of the real power output of these particular resources.

The researchers found that with very few exceptions existing distribution-connected generation projects representing VAR resources are optimally dispatched at a power factor other than unity, and that their ideal power factor changes as system operating conditions change. As discussed below, this suggests that to realize the full network performance benefits of the existing distributed generation resources, the reactive power capability of these generators should be made available to the network operator. Further, these resources should be included in a distribution automation scheme in which dispatch instructions are derived from actual system conditions and delivered to individual resources remotely. At the same time, the researchers see little value from dispatch of the real output of these units.

3.2.5. Alternate Topologies

Networked Topology

The researchers evaluated networked topologies as described in Section 2.2.7 for the 2005 Hobby system through a series of sequential switch closures or networking "steps" implemented in order of their posited impact on system performance as estimated through an GRIDfast™ optimization. Each successive step results in an increasingly networked system, until all existing tie switches are closed and the system is fully networked by definition. The researchers considered a set of 563 existing, open inter-circuit ties as candidates for networking.

Figure 5 and Figure 6 illustrate the voltage and loss impacts of the successive networking steps, in this case under normal summer peak conditions. The researchers can initially conclude that there are clear voltage and loss benefits from networked topology.

More importantly, though, in Figure 5 nearly all of the impact on the system minimum voltage of all of the potential steps is achieved within the first 30-40 steps. This confirms the researchers' expectation that a few networking steps would yield most of the benefit. The top-ranked 37 steps, if implemented, would increase the overall minimum voltage by 0.045 PU, or about 5%.

In Figure 6, the loss impacts from increased networking are less focused on a high-impact group, but visibly begin to decline around Step 350. The highest-ranked 350 steps would achieve real power loss reduction of 7.44 MW, without adding any new resources to the system.

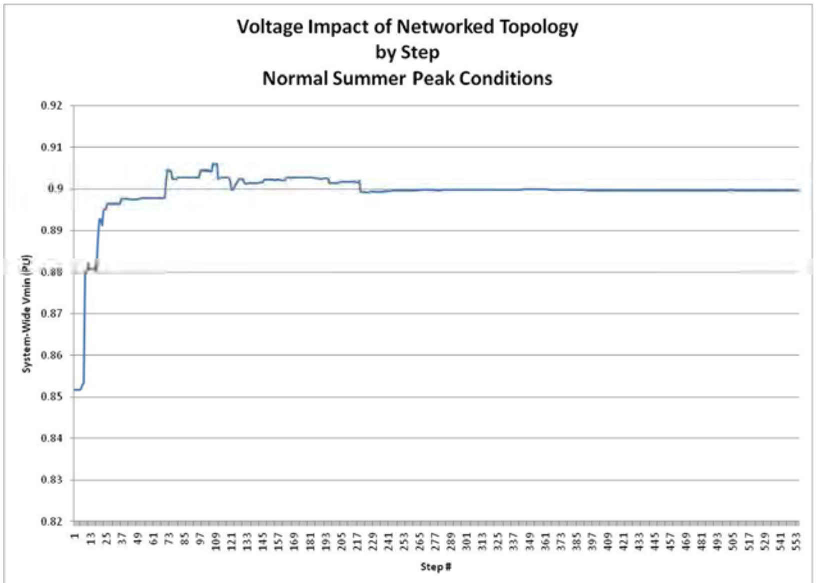

Figure 5. Voltage impact of networked topology

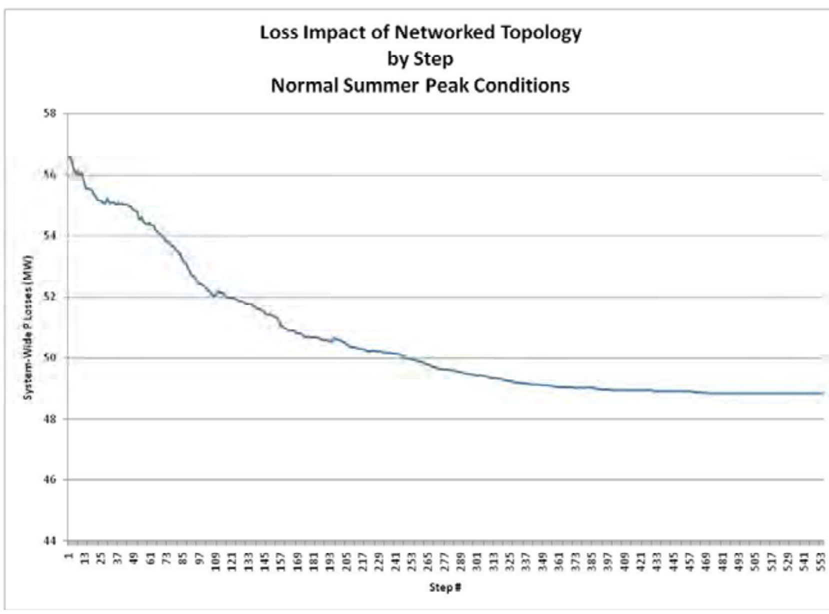

Figure 6. Loss impact of networked topology

Therefore, the researchers can also conclude that a partially networked, or "lightly meshed" system topology would achieve most of the same benefits of a fully networked system, particularly in terms of mitigation of systemwide minimum voltage.

Figure 5 also illustrates what the researchers have found to be a common voltage phenomenon in these stepwise analyses. Figure 5 shows voltage after each networking step at a single point in the system – the point with the lowest voltage. In most steps, that voltage improves, but it does not improve with every step. Within each networking switch closure, the system is seeking to re-optimize voltage and losses at every point, using hundreds of available capacitors and transformer taps. Thus, a measure such as the systemwide minimum voltage taken at a single point is subject to some noise; at the same time, however, the researchers also have found that systemwide average voltage, as a measure of performance improvement is too attenuated to see step-to-step changes. For that reason, the researchers tend to use voltage measurements to identify inflections points revealing a set disproportionately valuable measures (such as networking steps in this case), but then consider the measures in that group as a set, downplaying their individual rank within the set and their individual impact.

Among the 37 highest-ranked networking steps under this set of conditions, there are 28 unique circuit pair ties. In other words, only a few circuits are represented in these high-value networking steps, and several of those circuits are represented more than once.

With deeper study the researchers found that one circuit, Peach, has most of the lowest-voltage buses in the system, and remained so through many of the networking steps. Further, several of the highly ranked networking steps were repeat ties of Peach to neighboring circuits. The researchers also found circuits such as Bordeaux whose voltage improved even without direct participation in any networking steps.

To assess the performance of networked topology over varying conditions, the researchers performed the same type of analysis of the 2005 Hobby system under super-peak and winter peak conditions. Figure 7 compares the voltage impact results under the three sets of conditions.

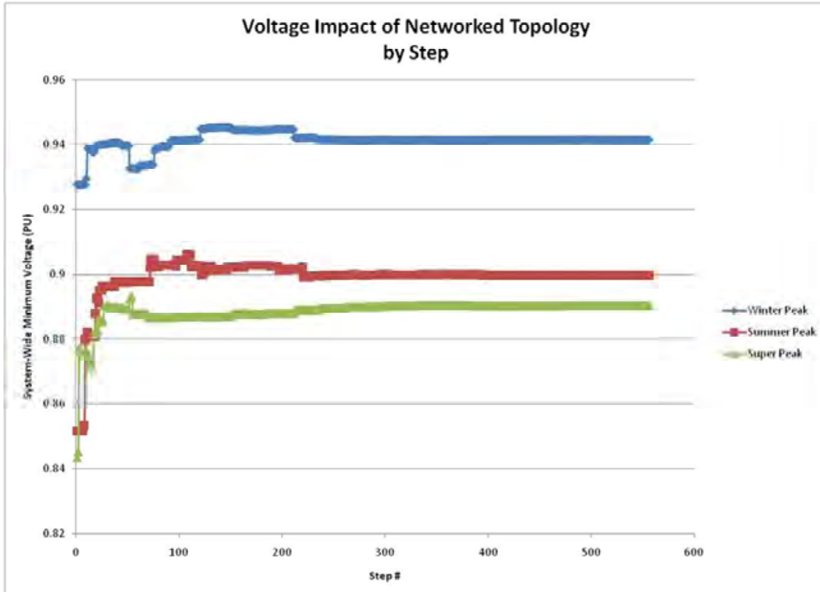

Figure 7. Seasonal comparison of voltage impact of networked topology

Under super-peak conditions, the researchers found a similar voltage inflection point, indicating a set of high-value networking closures, even though the overall voltage improvement is not as great due to the loading of the system. Under winter peak conditions, the initial voltage conditions are better, and the improvement from particular high-value networking switch closures is less distinct.

Considering the superset of the "high-value" networking switch closures across different operating conditions, the researchers identified 128 switch closures. Of these networking switch closures, 15 would be implemented under all conditions, or permanently, 4 would be implemented only under summer peak and super-peak conditions, and 19 would vary from season to season, turned on and off under different conditions, for a total "portfolio" of 38 networking switch closures. The remaining 90 switch closures would only be implemented under winter peak conditions. In light of the relatively small voltage benefit networking under winter peak conditions, the researchers would judge them highly discretionary.

The system operating partially networked via these switches as directed would yield the benefits summarized in Table 18 below. The individual switches in the "portfolio" of 38 networking switch closures are listed in Table 19.

Table 18. Performance benefits of 2005 "Networking Portfolio"

Conditions	V min Improvement	P Loss Reduction (MW)
Summer peak	4.5%	1.32
Super-peak	4.7%	1.05
Winter peak	1.1%	0.21

Table 19. 2005 Hobby system Top 38 networking switch closures

Profile	Device	Joins Circuits		Joins Substations	
Permanent	PS0856	Peach	Carter	Fruit (115/12)	Weckl (33/12)
	RCS0253	Jaguar	Griffon	Wildcat (115/12)	Dog (115/12)
	PS0727	Peach	Apple	Fruit (115/12)	
	RCS1384	Clam	Burmese	Cockle P.T. (33/12)	Balinese P.T. (33/12)
	GS2797	Canvas	Shorter	Paint (115/12)	Weckl (33/12)
	PS1510	Ink	Orange	Paint (115/12)	Fruit (115/12)
	PS0263	Violin	Griffon	Music (115/12)	Dog (115/12)
	PS1750	Tiller	Tender	Boat (115/33)	
	2245197E	Peach	Orange	Fruit (115/12)	
	PS1593	Eric	Grapefruit	Corea P.T. (33/12)	Fruit (115/12)
	PS1520	Apple	Pear	Fruit (115/12)	
	PS0959	Ink	Orange	Paint (115/12)	Fruit (115/12)
	PS0254	Peach	Apple	Fruit (115/12)	
	PS0801	Palette	Dinghy	Paint (115/12)	Preventer (33/12)
	PS1363	Palette	Roan	Paint (115/12)	Horse (115/12)
Summer peak + super-peak	PMH2252	Wrasse	Goldfish	Fish (115/12)	
	PS0997	Redwood	Towel	Tree (115/12)	Polo (115/12)
	OS1410	Barque	Blanket	Boat (115/12)	Ride (115/12)
	OS1896	Shovel	Rich	Garden (115/12)	Jazz (115/12)
Seasonally varying	GS5491	Goalie	Towhee	Polo (115/12)	Macaw (33/12)
	OS2155	Pine	Oak	Tree (115/12)	
	PS1977	Wren	Twain	Parrot (33/12)	Author (115/12)
	PS1397	Winch	Catboat	Vang P.T. (33/12)	Boat (115/12)

Profile	Device	Joins Circuits		Joins Substations	
	OS1068	Rose	Dahlia	Flower (115/12)	
	12160S	Vanadium	Mussel	Metal (115/12)	Oyster (33/12)
	RCS0952	Hubbard	Carter	Weckl (33/12)	
	PS1374	Redwood	Pine	Tree (115/12)	
	PS0730	Spruce	Cedar	Tree (115/12)	
	PS1836	Lobster	Eagle	Fish (115/33)	Tree (115/33)
	BS2332	Crow	Parrot	Owl P.T. (33/12)	Sandpiper P.T. (33/12)
	PS0957	Hubbard	Orange	Weckl (33/12)	Fruit (115/12)
	PS0887	Brush	Grapefruit	Paint (115/12)	Fruit (115/12)
	315871S	Grapefruit	Pear	Fruit (115/12)	
	PS0962	Orange	Grapefruit	Fruit (115/12)	
	PS0850	Peach	Orange	Fruit (115/12)	
	PS1507	Tobiano	Smock	Horse (115/12)	Paint (115/12)
	OS0964	Marsalis	Tobiano	Weckl (33/12)	Horse (115/12)
	PME1030	Armstrong	Eric	Jazz (115/12)	Corea P.T. (33/12)

The researchers also conducted a study of the potential benefits to the 2011 Hobby system of alternate topology, specifically networked topology. The researchers simulated the sequential closure of the available inter-circuit ties, going from a radial topology to a fully networked topology, in order of the impact of each switch closure on voltage and losses as assessed using GRIDfast™ . The voltage impacts of these networking steps are shown in Figure 8 and Figure 9. Figure 8 suggests that the impact on the systemwide minimum voltage from networked topology is relatively modest; except at step 37, which happens to join the system's one low-voltage circuit to a higher-voltage sibling circuit. Figure 9 suggests that there is an ongoing improvement in voltage variability, and increasingly flat voltage profile, with declining marginal benefit setting.

Figure 10 shows the loss impact of networked topology. It is evident that the first 14 or so networking steps yield a considerable loss benefit; to achieve the same level of loss reduction with further networking steps would require many closures and a more heavily networked topology. Based on this, the researchers conclude that even a lightly networked topology can yield meaningful network performance benefits.

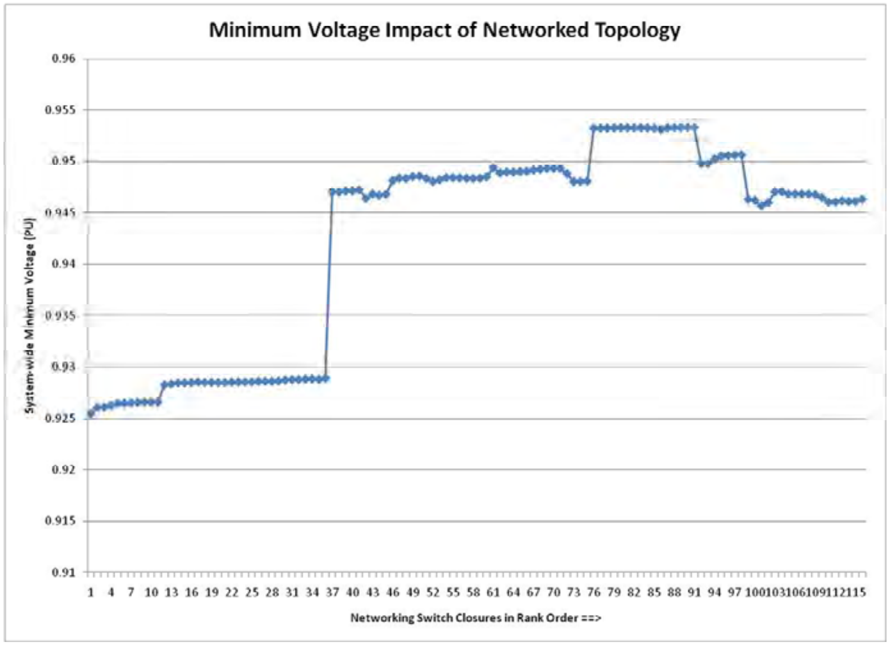

Figure 8. Minimum voltage impact of networked topology

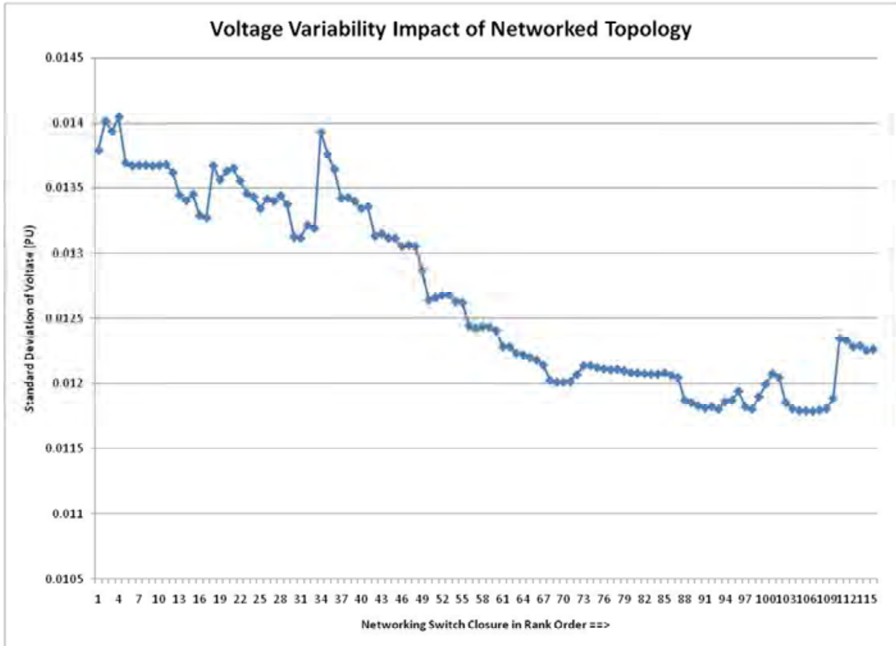

Figure 9. Voltage variability impact of networked topology

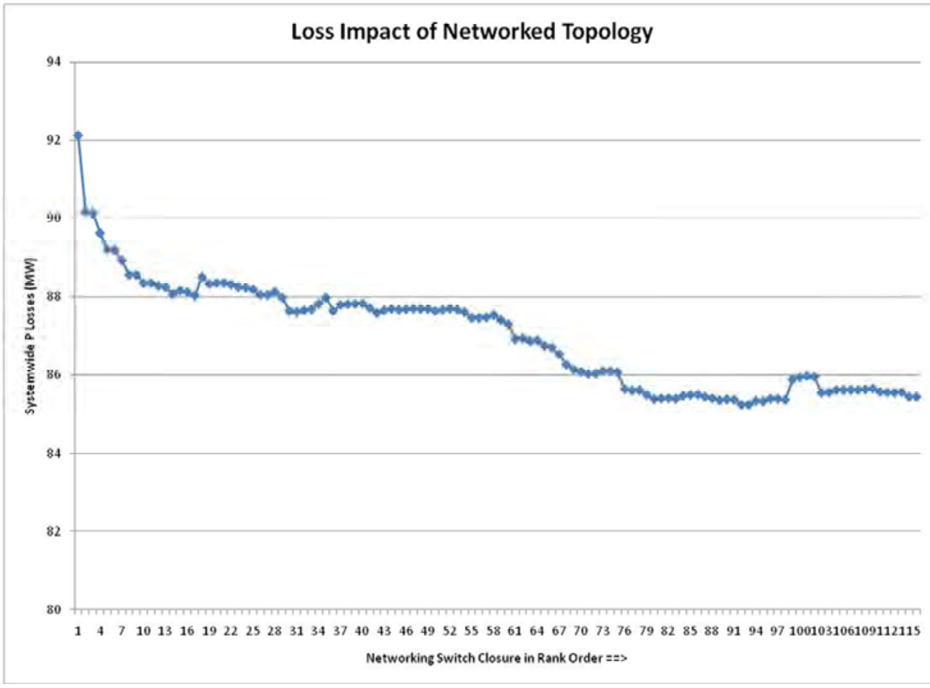

Figure 10. Loss impact of networked topology

The ranking of these networking switch closures is driven by the difference in P Index or real resource sensitivity (surplus or deficiency) across each open switch, so the closure should reduce losses and voltage variability. However, the closure may also indirectly provide load relief if a loaded circuit or substation is joined with one that is less loaded. Table 20 lists these 14 top-ranked networking steps with the circuits they join, and the substations and systems they join where the connections are not between circuits of the same substation.

Table 20. 2011 Hobby system Top 14 ranked networking steps

Switch	Circuits Joined	Substations Joined	Systems Joined
PS0263	Violin-Griffon	Music-Dog	Music-Dog
PS1630	Horseshoe-Drum	Ride-Music	Ride-Music
BDS2332	Crow-Parrot	Owl-Sandpiper	
12160S	Vanadium-Mussel	Metal-Oyster	Metal-Shellfish
GS5028	Shrimp-Cadmium	Oyster-Metal	Shellfish-Metal
RCS1384	Clam-Burmese	Cockle-Balinese	Shellfish-Wildcat
RCS1965	Cedar-Sprint		
GS5511	Gull-Muscat	Puffin-Grape	Bird-Grape
RCS2224	Barbera-Reisling		
RCS7076	Muscat-Barbera		
PS0311	Drum-Bridle	Music-Ride	Music-Ride
PME5303	Bay-Guitar	Horse-Music	Horse-Music
PS1510	Ink-Orange	Paint-Fruit	Paint-Fruit
BS0007	Morrison-Decartes		

These networking steps may provide some load relief for Oyster, Music, and Paint identified as loaded in 2011. However, the load relief needed for Oyster substation, 21 MW, would most likely not be meaningfully addressed through these networking switch closures.

This set of networking steps also provides redistribution of loads on circuits served from Metal substation identified in the Hobby system capital plan

Optimized Radial Topology

Based on the results for the benefits of networked topology described above, the researchers expected the main benefit of topology changes to show up in a relatively small number of moves. Therefore, the researchers decided to carry a topology optimization study for the 2005 Hobby system through 20 "steps," each step consisting of a switch closure paired with a switch opening, initially to assess the efficacy of this approach.

Each "step" commenced with identifying for closure the tie switch showing the largest difference in P resource deficiency using GRIDfast™ . The researchers then used the topology features of the Energynet® model to identify a second switch to open to retain the radial topology of the system. The researchers implemented both changes, and then re-solved the power flow. The researchers found that usually exists more than one sectionalizing switch that could be opened to configure radial system. To illustrate, opening either one of the main circuit breakers of the two circuits joined through the closed tie would return the topology to radial; however, neither is likely to be a desirable choice. In choosing, the researchers considered the direction of the load shift and the share of the circuit shifted. The researchers adapted the GRIDfast™ analytics to show not only the difference in resource deficiency across an open switch but also the sign, to reveal the appropriate direction of the shift. Determining the share of the circuit to shift remained at least partially a matter of judgment and trial and error.

The researchers found that from time to time a switch close/switch open step would result in a system configuration that is nominally infeasible, or for which the power flow would not converge to a solution, generally due to high mismatch at one or more buses. Procedurally in these instances, the researchers would move on to the next highest-ranked switch to close. However, the researchers also investigated two such instances in detail; the researchers sought to determine if the failed convergence might be due to a) a large difference in impedance of the lines connected to a high-mismatch bus, or b) a large difference in the power angle across the switch that was closed. In such cases, the configuration might still be physically possible to implement. However, in this particular set of results neither of these factors seemed to consistently explain the failure of these two steps alongside the successful convergence of the other steps. In fact, the failed convergence seemed clearly due to a large amount of load carried over in the shift. Most of the steps represented about 800 – 1,200 kVA of connected load, while one unsuccessful step would have represented over 12,000 kVA.

The researchers repeated this process for summer peak, super-peak, off-peak, and winter peak operating conditions. In each case, the researchers viewed the set of 20 steps as a single high-value group, with the ranking among them or the individual contributions of each step not material.

In the course of the study, the researchers discovered that once a switch was opened later in the sequence it might actually later become the switch bridging the largest resource deficiency and thus the next best candidate for closure. The researchers adapted the project approach, effectively adding opened sectionalizing switches to the pool of candidate tie switches for closure. Previously opened switches in fact came up frequently as choices for closure; however, in some cases the direction of the step would reverse a prior step, and in other cases add to a prior step. Given the project's finding that the amount of load moved in a step is important, this actually represents a feedback element. If a step moves "too little" load to resolve the resource deficiency difference, the process later expands it, and if it moves "too much" load, creating a new resource deficiency, the process later reverses the step. The sectionalizing switch choices are thus determined in a more systematic way; this suggests that the first choice of sectionalizing switches based on human judgment is often not the "best."

The researchers did not fully automate the topology optimization step process due to the need to identify the radicalizing switch opening to pair with the switch closure. Thus as implemented in this project the process described was time consuming even for just 20 steps. However, the researchers believe it could be fully automated, making it much more practical.

Figure 11 shows the systemwide minimum voltage after 19 topology optimization steps under normal summer peak conditions. An improving trend is clear, and the trace suggests the point of diminishing returns may be near.

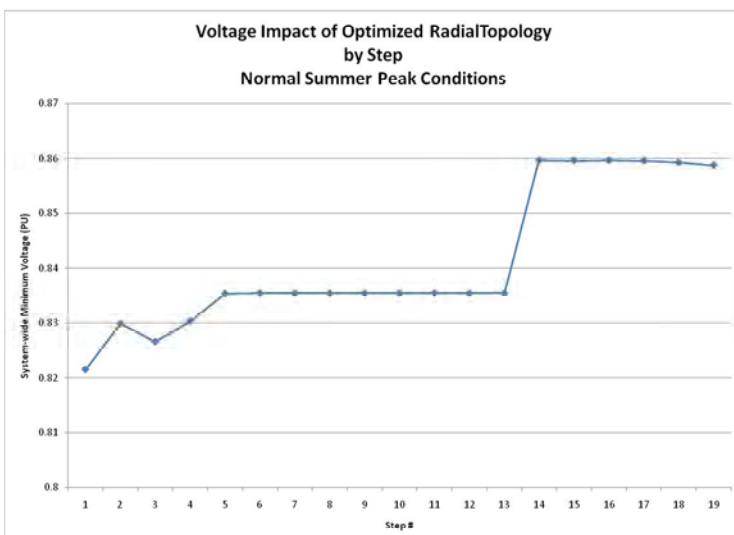

Figure 11. Voltage impacts of optimized radial topology (1)

Figure 12 shows a more evolved set of results from after the researchers modified the project's process to make opened switches eligible for reclosing. Figure 13 shows the systemwide minimum voltage impact of 20 steps, "net" after reversals and nominally about 36 steps. Figure 13 shows a clear voltage benefit and a clear leveling off. This suggests that additional load shifts beyond these 20 would not appreciably mitigate minimum voltage. Further, when compared to the voltage impacts of networked topology under super-peak conditions above, it is evident that this type of radial topology optimization cannot yield the same level of voltage improvement as even slightly networked topology can. The networked topology systemwide minimum voltage levels off at about 0.89 PU, where the optimized radial topology voltage levels off at about 0.845 PU.

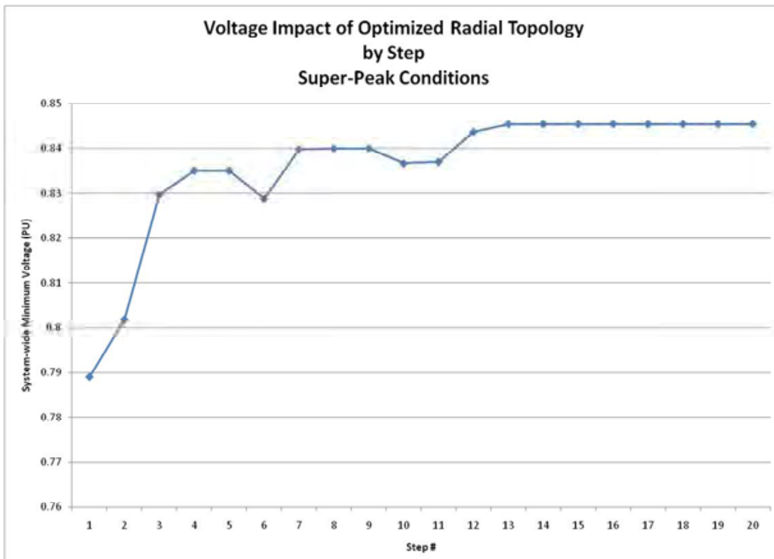

Figure 12. Voltage impacts of optimized radial topology (2)

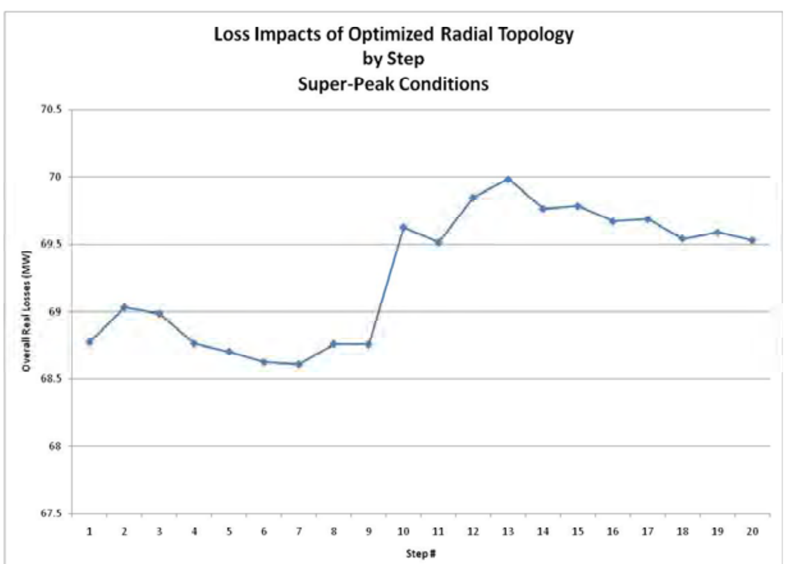

Figure 13. Loss impacts of optimized radial topology

Figure 13 shows the loss impacts of the same set of topology-optimizing steps as Figure 12. There is no discernable net improvement in losses. Again, a comparison with the loss impact of networked topology above suggests that optimized radial topology of this type will not have an appreciable loss benefit.

Table 21 lists the distinct topology-optimizing steps emerging from separate 20-step analyses performed for summer peak, winter peak, super-peak, and off-peak conditions for the 2005 Hobby system. "From" and "To" refer to the direction of the load shift in the step. One step, closing RCS0353 and opening PS0029 to shift load from Jaguar to Griffon, was among the top 20 steps under every operating condition, suggesting a permanent shift. The rest are appropriate under specific conditions or sets of conditions. This is, in effect, a set of load shifts that could be implemented daily or seasonally to improve minimum voltage, mainly, but also affect losses. If this set of shifts were implemented, the loss and voltage impacts would be as summarized in Table 22.

Table 21. Optimized radial topology switch steps

From Ckt	To Ckt	From Sub	ToSub	Close	Open
Jaguar	Griffon	Wildcat (115/12)	Dog (115/12)	RCS0353	PS0029
Appaloosa	Viola	Horse (115/12)	Music (115/12)	PS1565	PS1021
Apple	Peach	Fruit (115/12)		PS0727	PS0876
Apple	Pear	Fruit (115/12)		PS1520	PS1262
Apple	Pear	Fruit (115/12)		PS0930	PS0929
Blanket	Barque	Ride (115/12)	Boat (115/12)	OS1410	GS2711
Bluebird	Hemmingway	Heron (33/12)	Author (115/12)	OS1665	OS1660
Bluebird	Steinbeck	Heron (33/12)	Author (115/12)	PME4016	PME3051
Bluebird	Steinbeck	Heron (33/12)	Author (115/12)	PME5071	PME4016
Carter	Hubbard	Weckl (33/12)		RCS0952	264453S
Clam	Burmese	Cockle P.T. (33/12)	Balinese P.T. (33/12)	RCS1384	RCS1677
Dinghy	Palette	Preventer (33/12)	Paint (115/12)	PS0801	PS0809
Dinghy	Bay	Preventer (33/12)	Horse (115/12)	RCS0266	PS1089
Ellis	Yacht	Jazz (115/33)	Boat (115/33)	PS1602	PS0040
Ellis	Yacht	Jazz (115/33)	Boat (115/33)	PS0040	PS1421
Griffon	Violin	Dog (115/12)	Music (115/12)	PS0263	PS1742
Guppy	Tang	Fish (115/12)		GS5525	PME5334
Halyard	Sheet	Preventer (33/12)	Vang P.T. (33/12)	PS1710	PS1075
Malamute	Basenji	Dog (115/12)		OS1978	OS1987
Malamute	Rose	Dog (115/12)	Flower (115/12)	OS1068	OS1644

From Ckt	To Ckt	From Sub	ToSub	Close	Open
Marsalis	Tobiano	Weckl (33/12)	Horse (115/12)	PS0153	PS0330
Muscat	Barbera	Grape (115/12)		PS1846	PS4884
Net	Towel	Polo (115/12)		RCS0941	PS0981
Oak	Redwood	Tree (115/12)		OS1242	OS1242
Oak	Pine	Tree (115/12)		OS2155	OS2155
Orange	Hubbard	Fruit (115/12)	Weckl (33/12)	PS0957	PS0772
Orange	Ink	Fruit (115/12)	Paint (115/12)	PS1510	RAR0963
Orange	Ink	Fruit (115/12)	Paint (115/12)	PS0959	PS0958
Peach	Orange	Fruit (115/12)		GT3912OT	PS0850
Peach	Apple	Fruit (115/12)		PS0727	PS0208
Peach	Apple	Fruit (115/12)		PS0727	PS0876
Peach	Carter	Fruit (115/12)	Weckl (33/12)	PS0856	PS0060
Peach	Orange	Fruit (115/12)		PS0850	PS0182
Peach	Apple	Fruit (115/12)		PS0850	PS0182
Pear	Apple	Fruit (115/12)		PS1520	PS0931
Pine	Oak	Tree (115/12)		OS2155	OS2154
Redwood	Pine	Tree (115/12)		PS1374	PS0996
Redwood	Towel	Tree (115/12)	Polo (115/12)	PS0997	PS0853
Riesling	Zinfandel	Grape (115/12)		GS4378	PS4302
Riesling	Zinfandel	Grape (115/12)		PME5245	PME4673
Shorter	Canvas	Weckl (33/12)	Paint (115/12)	GS2797	GS2841
Shorter	Ink	Weckl (33/12)	Paint (115/12)	PS0883	PS1752
Shorter	Ink	Weckl (33/12)	Paint (115/12)	PS0338	PS1752
Shovel	Rich	Garden (115/12)	Jazz (115/12)	OS1896	OS1894
Spaniel	Griffon	Dog (115/12)		RCS1124	PS0989
Tender	Tiller	Boat (115/33)		PS1015	PS1014
Tender	Tiller	Boat (115/33)		PS1750	PS1015
Tern	Oak	Crane (33/12)	Tree (115/12)	RCS1551	GS3058
Terrier	Basenji	Dog (115/12)		GS2148	GS2148
Tiller	Tender	Boat (115/33)		PS1750	PS1709
Tobiano	Marsalis	Horse (115/12)	Weckl (33/12)	PS1400	PS0286
Tobiano	Smock	Horse (115/12)	Paint (115/12)	PS1398	PS0827
Tobiano	Shorter	Horse (115/12)	Weckl (33/12)	OS1111	OS1111

From Ckt	To Ckt	From Sub	ToSub	Close	Open
Tobiano	Marsalis	Horse (115/12)	Weckl (33/12)	OS0964	OS1111
Tobiano	Marsalis	Horse (115/12)	Weckl (33/12)	OS0964	OS0964
Tobiano	Smock	Horse (115/12)	Paint (115/12)	PS1507	PS1398
Towel	Redwood	Polo (115/12)	Tree (115/12)	PS0997	PS1881
Violin	Griffon	Music (115/12)	Dog (115/12)	PS0263	PS1358
Wrasse	Hawkfish	Fish (115/12)		PS1775	RCS0733
Wrasse	Goldfish	Fish (115/12)		PME5063	PME5004
Wrasse	Goldfish	Fish (115/12)		PMH2252	PME5063
Wrasse	Cadmium	Fish (115/12)	Metal (115/12)	PME5106	GS5298
Wren	Twain	Parrot (33/12)	Author (115/12)	PS1977	RCS0760

Table 22. Performance benefits of "Optimized Radial Topology Portfolio"

Conditions	V min Improvement	P Loss Reduction (MW)
Summer peak	3.7%	-0.973
Super-peak	5.6%	-0.758
Winter peak	0.8%	-0.053
Off peak	0.8%	0.14

This "portfolio" of topology changes for the 2005 Hobby system represents 100 individual switches and affects 52 circuits.

Distribution Automation – Switch Automation

The researchers found discrete, quantifiable potential network performance benefits that would require, and result from, routine manipulation of certain individual, identified switches in the Hobby system. These performance benefits arise from: a) seasonal or daily topology changes to maintain optimized topology, discussed above, and b) reduced restoration time through post-contingency load shifts. Therefore, high-value candidates for switch automation are those individual switches shown to have a recurring role in maintaining optimal topology or whose automation alone would change posited post-contingency load restoration times. These switches are thus attractive candidates for remote control and monitoring, with quantifiable potential benefits attributable to that capability.

If the utility operating the Hobby system chose to adopt a partially networked topology policy, the "seasonally varying" switches listed in Table 19 are also the switches that are the most valuable candidates for automation. At the same time, the ideal networked topology could be delivered effectively with "permanent" networking closures as "set and forget", and the "summer + summer peak" closures set manually on a seasonal basis. Therefore, the automation of these switches yields arguably less incremental benefit. Therefore, the automation of only 19 switches[25] systemwide yield the performance benefits summarized in Table 18.

If the utility operating the Hobby system chose to maintain a radial topology policy, the switches listed in Table 21 are the highest-value candidates for automation. RCS0353 and PS0029 would be repositioned permanently, and do not benefit from automation. Of the remainder, switches supporting steps that yield benefits only under off-peak conditions (and are reversed daily under peak conditions), or switches supporting steps yielding benefits under super-peak conditions only (and must be repositioned quickly and with short notice when such super-peak conditions occur) may be particularly attractive. Automation of all of these switches would yield the potential benefits summarized in Table 22. Excluding RCS0353 and PD0029, within Table 21 there are 100 unique switch devices, of which five are already automated.

The reliability assessment the researchers performed included consideration of the circuit-level reliability impacts of the availability or absence of automated switches for post-contingency load transfers. Of the 215 circuits in the 2005 Hobby system, 169 reflected some level of increased risk for unserved load in the researchers' analysis due to limited post-contingency load transfer opportunities or capacity under at least one set of operating conditions. Accordingly, switch automation alone would not directly address these reliability issues. However, the researchers found 98 circuits with adequate post-contingency load-transfer opportunities and capacity under all operating conditions, but no automated tie switches. Automated switches on these circuits would arguably provide a direct reliability benefit as a purely standalone measure.

The researchers also found 65 circuits that have available load transfer opportunities and automatic or remotely operable tie switches. Additional switch automation on these circuits would arguably have less incremental impact on reliability, though there may well be individual load transfer operations that would be expedited with additional automation.

3.2.6. Optimal DER Portfolio Additions

Capacitors

For the 2005 Hobby system, the Optimal DER Portfolio capacitor additions consist of 157 capacitors at sites on 53 circuits. These capacitors are each either 150 or 300 kVAR in size, and in aggregate total 42,150 kVAR. 77 of these capacitors would operate under at least two of the five operating conditions the researchers analyzed, and 25 would operate under three or more.

Of the 157 capacitors, 22 capacitors on eleven circuits provide disproportionate voltage benefits under one or more of the operating conditions the researchers analyzed. Nine of those are on one circuit: Peach. Two capacitors, one on Spaniel and one on Peach, are among those identified as providing disproportionate voltage benefits under every set of operating conditions. One of these would also operate under all five operating conditions, and the other would operate under all but the winter peak condition.

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25. This number is actually somewhat overstated as some of these switches are already automated.

Under normal summer peak conditions, the researchers identified 83 capacitor additions that nominally enhance network performance within the Hobby network. As a group, these capacitor additions increase the system's lowest single-point voltage from 0.808 to 0.899 PU, an increase of 0.091 PU. These capacitor additions also reduce the system's real (P) losses from 56.115 MW to 55.799 MW, a reduction of 316 kW, with no reduction in load served or addition of new P capacity.

As shown in Figure 14 and Figure 15, the 20 capacitor additions that are the highest ranked in terms of network benefits (capacitor addition steps 1 through 20) have the greatest impact on the system's overall lowest voltage, increasing it from 0.81 PU to over 0.89 PU. These 20 capacitor additions also have the greatest impact on systemwide P losses, reducing P losses from 56.115 MW to 55.757 MW, a reduction of 358 kW. They also account for 647 of the 715 buses whose voltage increases to above 0.95 PU.

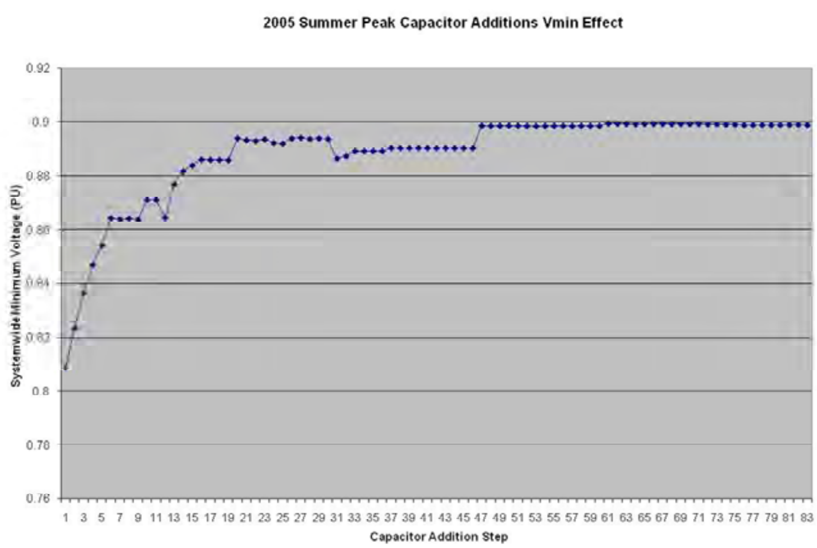

Figure 14. Voltage impacts of 2005 summer peak capacitor additions by step

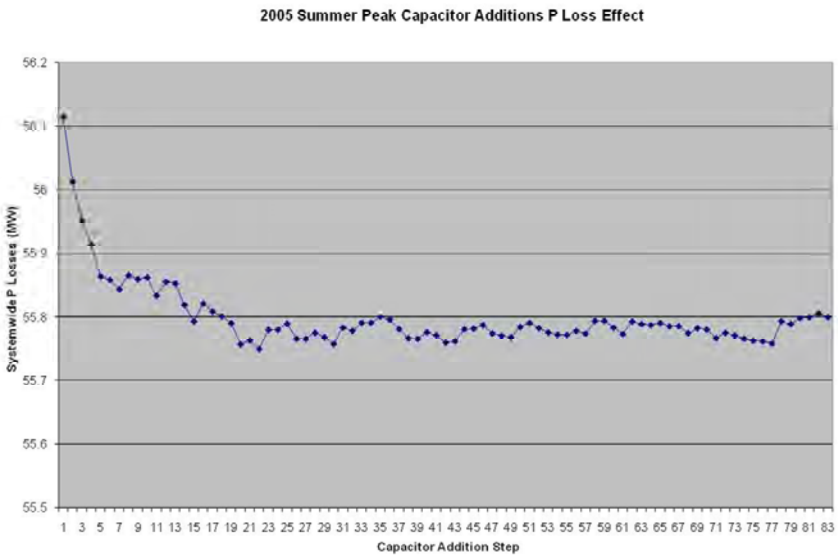

Figure 15. Loss impacts of 2005 summer peak capacitor additions by step

Under summer super-peak conditions, the researchers identified 104 capacitor additions that nominally enhance network performance. As a group, these capacitor additions increase the overall systemwide minimum voltage from 0.793 to 0.898 PU, an increase of 0.105 PU. They reduce the number of buses in the Hobby system under these conditions with voltage under 0.95 PU by 1,769, from 2,857 to 1,088. They also reduce systemwide P losses from 67.718 MW to 67.093 MW, a reduction of 625 kW.

The voltage and loss impact profiles of these additions in rank order are analogous to that shown for the summer peak capacitor additions in that a subset has a disproportionate impact. Among these 104 capacitors, the seven highest-ranked capacitor additions have the most significant impact to the system's overall minimum voltage, increasing it by 6.2 percentage points from 0.793 PU to 0.855 PU. They also reduce the number of low-voltage buses by 270 from 2,857 to 2,587. The seven highest-ranked capacitor additions also have the greatest impact on systemwide P losses, reducing P losses from 67.718 MW to 67.463 MW, a reduction of 255 kW.

The GRIDfast™ analysis of the winter-peak, minimum-load, and off-peak hour cases yielded Q-Index result that suggest that the system under these conditions is nearly in balance with respect to Q resources, and there is relatively little benefit to be obtained from additional reactive capacity additions. In addition, as the optimization objective function incorporates losses as well as voltage deviation, it is not surprising in a realm of very small overall improvements to see one indicator decline while the other improves.

Under winter-peak conditions, the researchers identified four capacitor additions on four different circuits that nominally enhance network performance. These capacitors together increase the systemwide median voltage from 1.0085 to 1.0087 PU, and reduce the number of buses with voltage under 0.95 PU from 978 to 649. They have a negligible effect on the systemwide minimum voltage and systemwide losses.

Under minimum load conditions, the researchers identified 40 capacitor additions that nominally enhance network performance. As a group, these capacitor additions increase the systemwide minimum voltage from 0.982 to 0.989 PU, increase the systemwide median voltage from 1.0186 to 1.0188 PU, and reduce the voltage variability from 0.00856 to 0.00744 PU. These capacitor additions increase P losses from 5.539 MW to 5.739 MW, an increase of 200 kW.

The voltage and loss impact profiles of these additions in rank order are analogous to that shown for the summer-peak capacitor additions in that a subset has a disproportionate impact. The majority impact on the systemwide minimum voltage actually stems from the six highest-ranked capacitor additions. These also account for most of the reduction in voltage variability.

Under off–peak-hour conditions the researchers identified 39 capacitor additions that nominally enhance network performance. As a group, these capacitors increase the systemwide median voltage from 1.0167 PU to 1.0169PU, increase the systemwide minimum voltage from 0.9598 PU to 0.9698 PU, and reduce the voltage variability from 0.01034 PU to 0.00892 PU.

The voltage and loss impact profiles of these additions in rank order are analogous to that shown for the summer peak capacitor additions in that a subset has a disproportionate impact. The four highest ranked capacitor additions have the largest effect on the systemwide minimum voltage. These capacitor additions increase systemwide P losses from 10.594 to 10.745, an increase of 139 kW.

For the 2011 Hobby system, the researchers identified a set of Optimal DER Portfolio capacitor additions using a similar approach. The researchers identified 53 nominally beneficial capacitor additions; Figure 16 shows the voltage impact with each added to the system in rank order, and Figure 17 shows their loss impact. These results suggest first that the Hobby system has nearly sufficient reactive power compensation capacity with existing resources used to their full advantage. Further, all of the 53 sites are on individual distribution lines; the researchers found no benefit relative to the objective in any additional substation capacitors.

It is also evident that there are 3 individual capacitor additions that would yield nearly all of the potential benefits of the group of 53 capacitor additions relative to minimum voltage and loss improvement. These three capacitors are all located on Saddlebred circuit out of Horse substation, the one circuit with buses having voltage lower than 0.95 PU after recontrols. Addition of just the first three-ranked capacitors, representing 300 kVAR each or a total of 900 kVAR, would increase the systemwide minimum voltage by 0.0096 PU or 0.96% of nominal, and reduce losses by 2.3056 MW.

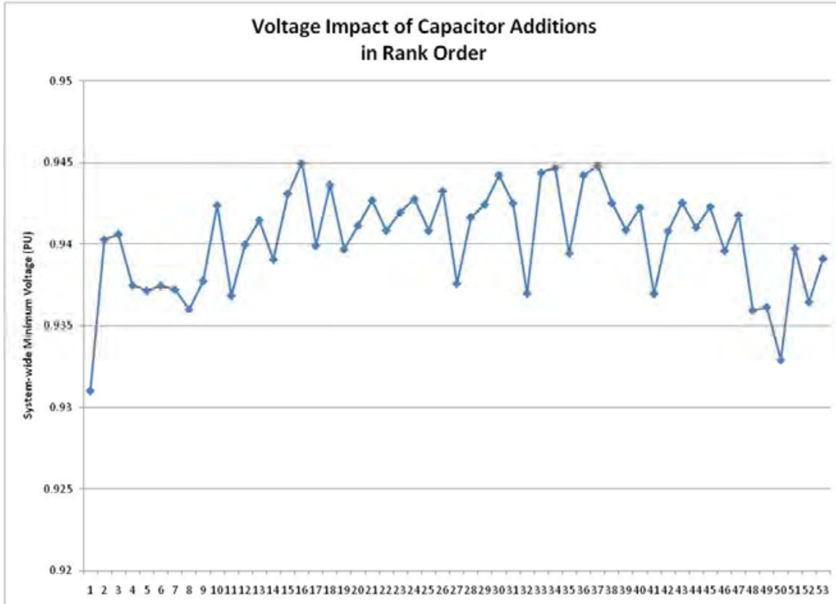

Figure 16. Voltage impact of 2011 capacitor additions

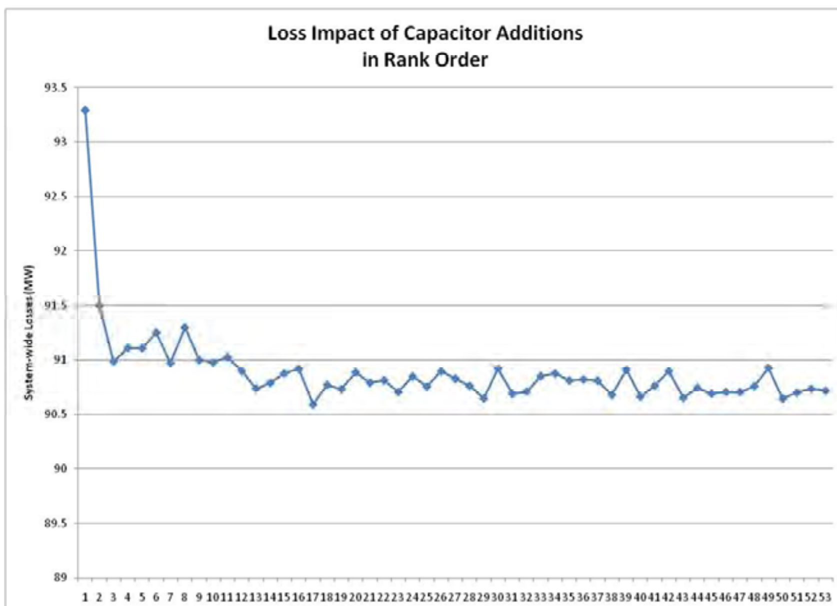

Figure 17. Loss impact of 2011 capacitor additions

Demand Response

The 2005 Optimal DER Portfolio includes 22,147 demand response additions representing available capacity of about 129 MW under super-peak conditions, or about 10% of super-peak load. 4,192 of these, representing available capacity of about 32 MW or 2.5% of super-peak load, are “voltage benefit” projects having disproportionate voltage impacts under summer peak, super-peak, and/or off-peak conditions,. The nominal or project total demand response capacity is about 133 MW for the full 22,147- project portfolio and about 33.7MW for the 4,192-project portfolio.

The full portfolio includes demand response projects at 3,305 non-residential and non-small business sites representing 9.79 MW under conditions other than super-peak and going to a potential of 49.58 MW under super-peak conditions. The portfolio also includes demand response projects at 18,842 residential and small business customer sites, generally HVAC cycling demand response, representing about 111 MW of demand reduction; however, these resources would be available under super-peak conditions only.

Of the 45,916 load-serving transformer sites in the 2005 Hobby system, the researchers found 1,234 that are not eligible for any demand response, and 4,732 that have existing demand response and are not eligible for demand response additions. Researchers found that 3,313 of the load-serving sites are eligible for new demand response projects outside summer super-peak operating conditions. Again, these sites are all non-residential, non-small business sites presumably with more sophisticated energy management capability; the researchers found nominally beneficial demand response projects at 3,305 of these sites.

Under the researchers’ assumptions, 36,637 sites in the 2005 Hobby system, generally residential and small business customers, are eligible for new demand response projects that would be available only during summer super-peak conditions. 18,842 of these sites, or only about half, were identified as yielding any network benefits under super-peak conditions.

The researchers modeled 4,732 existing demand response projects in the 2005 Hobby system. The researchers assumed these resources were only available under super-peak conditions. These represent 15.19 MW of demand reduction under those conditions. From these modeled projects, 48 sites showed no network benefits under super-peak conditions.

As stated above, under the researchers’ assumptions the majority of demand response sites, including all residential and small commercial sites, are available under super-peak conditions only. 39,950 sites are eligible for demand response under these conditions, in contrast to the 3,313 sites eligible periods under other than super-peak conditions.

In the researchers’ analysis, the researchers assumed that the existing demand response projects were available under super-peak conditions. In order to assess incrementally any network benefits that could be provided by new demand response projects, the value and ranking of potential new demand response projects under these conditions reflect the operation of the existing demand response resources.

Under super-peak conditions, the researchers identified 20,767 demand response additional projects that nominally enhance network performance. These projects represent a total of 128.72 MW, or about 6 kW per site.

As a group when dispatched, these additional demand response projects raise the systemwide minimum voltage from 0.905 PU to 0.935 PU, an increase of 3.0 percentage points and reduce systemwide P losses from 65.786 MW to 53.936 MW, a reduction of 11.85 MW. They also increase the systemwide median voltage from 1.0090 to 1.0106, reduce voltage variability from 0.0191 to 0.0147, and reduce the number of buses under 0.95 PU by 461 from 963 to 502.

The 3,000 highest-ranked demand response additions have the most significant impact on systemwide minimum voltage under these conditions, increasing it from 0.905 to 0.919 PU. They also reduce voltage variability from 0.0191 to 0.0171 and reduce the number of buses under 0.95 PU by 223 from 963 to 740. These projects reduce the systemwide median voltage slightly from 1.00905 to 1.00891 PU but increase the systemwide average voltage from 1.0055 to 1.00609.

Together the existing and new demand response projects represent 143.83 MW, or about 10.7% of the peak load under summer super-peak conditions.

Under 2005 normal summer peak conditions, the researchers identified 3,294 demand response projects that nominally enhance network performance from 3,313 eligible (non-residential or non-small business) sites. These projects together represent about 8.52 MW or an average of about 3 kW per site. These projects are on a small share of the system's load-serving buses and represent a small share of the total load, so their impact on network performance is small but positive.

As a group, these demand response projects increase the system's lowest single-point voltage from 0.89886 to 0.89895PU; they increase the systemwide median voltage from 1.009779 to 1.009786 PU, and reduce the systemwide voltage variability (standard deviation) from 0.0188 to 0.0186 PU. They also reduce the number of buses in the system with voltages under 0.95 PU from 1,163 to 1,154. As a group, these demand response additions also reduce the system's real power (P) losses from 55.796 MW to 55.157 MW, a reduction of 639 kW.

A greatly expanded scale reveals that the 1,003 highest-ranked demand response additions under these conditions have the greatest impact the system's lowest voltage, increasing it from 0.8988 PU to 0.8993 PU, and the impact of demand response additions on the systemwide minimum voltage actually levels off by about step 1,400. These 1,400 highest-ranked demand response additions also account for all of the buses whose voltage increases to over 0.95 PU.

Under 2005 winter peak conditions, the researchers identified 2,801 demand response projects that nominally enhance network performance from 3,313 eligible (non-residential or non-small business) sites. The impact of each of these additions individually on the systemwide minimum voltage is negligible, so the researchers did not identify a "voltage benefit" subset of these projects. The accumulated addition of capacity associated with these demand response projects allows TCUL step changes that raise the systemwide minimum voltage visibly with a highly magnified scale, so collectively these projects result in an increase in the systemwide minimum voltage from 0.9189 to 0.9190 PU.

The 2,801 demand response projects as a group reduce P losses from 19.507 MW to 19.120 MW, a reduction of 387 kW. They represent a total of 7.55 MW or about 3 kW per site.

Under 2005 minimum load conditions, the minimum P Index bus has P Index value equal to 0.40. This indicates that every bus in the system is nearly balanced or even slightly surplus in terms of real capacity. Accordingly, under these conditions, there is no demand response or distributed generation project that can improve network performance through the addition of real capacity.

By comparison, under 2005 off-peak hour conditions the minimum P Index bus has P Index equal to -0.93. This indicates there is some small real (P) capacity deficiency and opportunity to improve network performance through additions of real capacity, but less so then under summer or winter peak condition. In addition, the systemwide minimum voltage is already over 0.95 PU.

Under off-peak hour conditions the researchers identified 3,257 demand response projects that nominally enhance network performance from 3,313 eligible sites. As a group, these projects increase the systemwide minimum voltage from 0.9699 to 0.9726 PU and reduce P losses from 10.745 MW to 10.434 MW, a reduction of 311 kW. They also increase the systemwide median voltage from 1.0169 PU to 1.0170 PU and reduce voltage variability from 0.00892 to 0.00880.

The 300 or so highest-ranked projects individually yield slight improvements in the systemwide minimum voltage. The remainder improve voltage overall without direct improvements to the systemwide lowest voltage.

The 3,257 demand response projects as a group represent 8.32 MW, or an average of 2.55 kW per project.

The researchers also identified a set of "Optimal DER Portfolio" demand response projects for the 2011-forecast case using a similar approach. Figure 18 shows the impact of the over 23,000 nominally beneficial potential demand response additions on systemwide minimum voltage, each added to the system in rank order.

These additions together would represent 144.42 MW, or 8.46%, of the Hobby system's total load, and thus arguably represent an impractically large population of demand response projects. A loss analysis shows that there is little difference among the full set of 23,000 potential demand response projects in terms of loss impacts. For the 2005 Optimal DER Portfolio the researchers used the impact of each DER addition on systemwide minimum voltage as one measure of the overall voltage impact of each project and also to distinguish a "voltage benefit" subset from all of the nominally beneficial projects. Using this same approach, it is evident from Figure 18 that among these potential demand response additions there is a subset of about 3,000 projects that are "high value" by virtue of their having a disproportionate impact in terms of voltage.

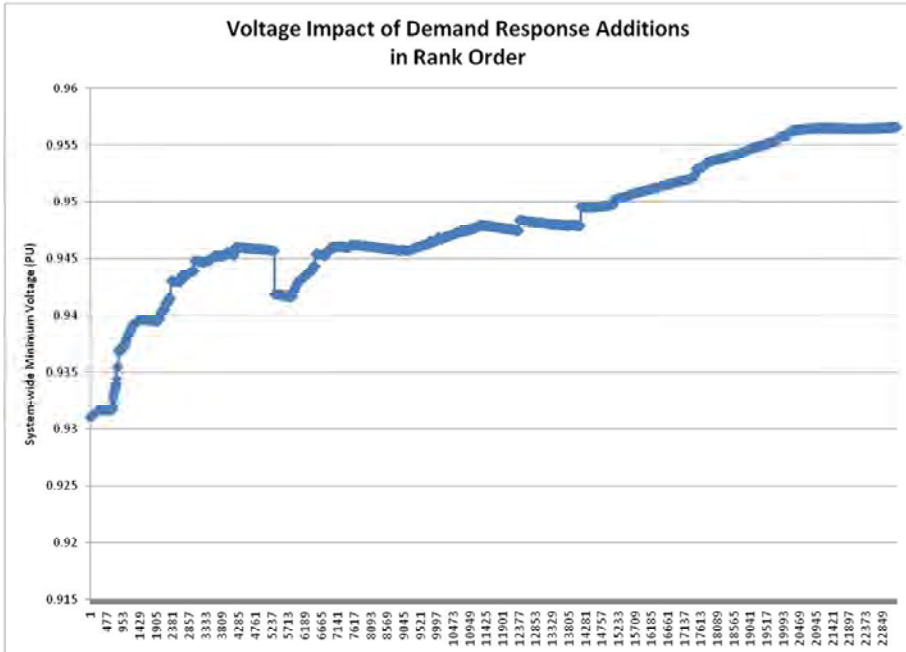

Figure 18. Voltage impact of 2011 DR additions

This high-value or "voltage benefit" subset of 3,000 demand response additions represents 14.93 MW, or about 0.87% of the Hobby system's load under these conditions. They lie on 55 different circuits, and increase the systemwide minimum voltage by 0.01290 PU or 1.29% of nominal when called or dispatched under these conditions. They would also reduce losses by 2.6695 MW when dispatched.

These demand response projects represent incremental capacity, available at least on a limited basis, to relieve localized peak period loads within the Hobby system *provided* they are dispatchable individually or by circuit. Table 23 shows the capacity of these 2011 Optimal DER Portfolio demand response projects mapped based on their locations to the substations identified previously as capacity deficient in the 2011 Hobby system forecast case simulation.

Table 23. 2011 Optimal DER Portfolio DR capacity in loaded substations

Loaded Substation	DR MW
Oyster	0.324
Fish	1.184
Shellfish	0.342
Limpet	
Metal	0.552
Macaw	0.369
Bobwhite	0.639

Loaded Substation	DR MW
Tree	1.230
Preventer	0.317
Modjazz	1.241
Weckl	1.223
Sail	0.336
Hawser	
Music	1.011
Paint	
Author	0.144
Bird	1.466
Heron	

Table 23 shows that the largest blocks of demand response capacity among the Optimal DER Portfolio projects are within Fish, Tree, Modjazz, Weckl, Music, Wildcat, and Bird substations. In terms of load relief, the demand response projects on circuits served from Weckl substation could possibly provide some load relief or capacity deferral benefit. Weckl substation overloads by only 1.28 MW under forecast conditions, so if loads develop slowly the demand response projects on circuits served from Weckl could be enough to defer an overload condition.

Table 24 shows the capacity of the 2011 Optimal DER Portfolio demand response projects mapped to the substations whose loading contributes to elevated reliability risk of the highest-risk circuits in the 2011 Hobby system identified through the reliability assessment. The demand response capacity on circuits served from Wildcat, Bird, and Tree substations is insufficient to permit those substations to continue to serve load under a loss-of-bank contingency. However, it could reduce the affected loads on those substations in such an event assuming the substation remains in service at a reduced level.

Table 24. 2011 Optimal DER Portfolio DR capacity in reliability-risk substations

Loaded Substation Affecting High-risk Circuits	DR MW
Wildcat	0.823
Bird	1.466
Tree	1.230
Fruit	0.010

Distributed Generation

The 2005 Optimal DER Portfolio includes 1,396 distributed generation additions, all of which that have disproportionate voltage benefits under one or more set of operating conditions. Each of these projects has a specified location, size, and operating profile. The operating profile is derived both from the project's type (e.g. PV can operate only during peak or daytime conditions), and from the operating periods during which the project is shown to deliver network benefits. The available capacity of these projects varies under different conditions and is 26.2 MW under summer peak. Their nominal capacity in aggregate is 35.206 MW.

Of the candidate 45,477 sites in the subject system eligible for potential new distributed generation, projects at 19,381 sites are shown to yield network benefits under one or more of the operating conditions the researchers modeled. All of these are identified in terms of their location, generator type (synchronous, inverter, or inductive), and size in kW based on the nature of the underlying customer, and the period(s) during which projects in those locations are shown to yield network benefits. These sites lie on 207 of the 215 circuits of the subject system.

Researchers found that 15,301, or nearly 80% of these sites, are residential PV projects, and 1,769 are small business PV projects. The 2,311 projects that remain are a mixture of large-scale PV at medium and large business sites, inductive generation, and synchronous generation.

Researchers found that 5,934 of these sites are shown to yield benefits under all three peak conditions – summer-peak, super-peak, and winter-peak conditions. There are 616 additional sites that are shown to yield benefits under both summer-peak and winter-peak conditions, but not under super-peak conditions, possibly due in part to the impact of the large amount of demand response capacity added in the super-peak case. Of these 6,550 sites, 215 non-PV projects show benefits under light load hour conditions as well.

There are a total of 1,396 sites that are among the sites identified above as providing disproportionately high voltage benefits under one or more of normal summer peak, winter peak, or light load hour conditions. These lie on 72 of the 215 Hobby circuits. 73 of these sites yield disproportionate voltage benefits under both normal summer peak and winter peak conditions. 1,124 of these sites are residential and small business PV projects, and 71 are PV projects at medium and large business and agricultural sites ranging in size from about 2 kW to 32 kW.

This group of 1,396 sites includes 130 inductive generator projects ranging in size from 37 kW to 119 kW and 71 synchronous generator projects ranging in size from 3.6 kW to 1,030 kW. These 201 inductive and synchronous generator projects are dispatchable under the networkers' assumptions; 50 yield network benefits during summer and winter peak conditions and off-peak hour conditions and would ideally be base loaded. Six should operate on a base load basis but during the winter season only, and 68 should operate on a base load basis during the summer season only. Eleven plus one of the winter seasonal baseload projects should operate only during the super-peak day, but during both peak and off-peak hours. 66 should operate only during off-peak hours. As stated elsewhere, super-peak dispatch profiles may be affected by the large amount of demand response the researchers included in the super-peak case.

The 73 projects that yield disproportionate voltage benefits under both summer peak and winter peak conditions lie on eleven of the 215 Hobby circuits. Researchers identified that 69 are residential and small business PV, one is an agricultural PV project, two are inductive generator projects, and one is a synchronous generator project. This synchronous generator project is a 180 kW project at a medium business site on the Malamute circuit that would operate at base load.

Its rank among distributed generation additions under normal summer peak conditions is 568, and it is arguably the highest-ranked traditional distributed generation project in the Hobby system. It is interesting that most of the potential large synchronous generator sites ranked relatively low in terms of network benefits, probably because they are located at relatively robust parts of the system.

Under normal summer peak conditions in the 2005 Hobby system, the researchers identified 15,945 distributed generation projects that nominally enhance network performance from 45,477 eligible sites. As a group, these distributed generation projects increase the system's lowest single-point voltage from 0.8989 PU to 0.9311, an increase of 3.2 percentage points, and reduce the systemwide voltage variability (standard deviation) from .0186 to .0158 PU. They also reduce the number of buses in the system with voltages under 0.95 PU by 415 from 1,154 to 739. As a group, these distributed generation additions also reduce the system's real power (P) losses from 55.157 MW to 36.831, a reduction of 18.326 MW.

These distributed generation additions actually decrease the systemwide median voltage slightly from 1.009786 PU to 1.009152. As the researchers add capacity associated with these distributed generation projects, the potential for high voltage is offset by redispatch of capacitors and TCULs. This redispatch will allow some bus voltages to fall even if within the 0.95 PU - 1.05 PU target range. In addition, the inductive generators add reactive load, potentially reducing voltage. Note that even as the median voltage decreases due to these distributed generation additions, the systemwide average voltage increases from 1.0059 to 1.0062 PU and the number of buses with voltages under 0.95 PU also decreases.

Figure 19 shows that of these distributed generation projects, there are about of the 1,000 highest-ranked in terms of network benefits have a disproportionate impact on the system's absolute lowest voltage, bringing it from 0.899 PU to 0.935 PU. They also account for 346 of the 415 buses whose voltage increases above 0.95 PU.

Because distributed generation adds P capacity (or reduces P load), every incremental addition potentially reduces losses. The researchers found no obvious inflection point, though there is some observable decline in the loss benefit of each addition.

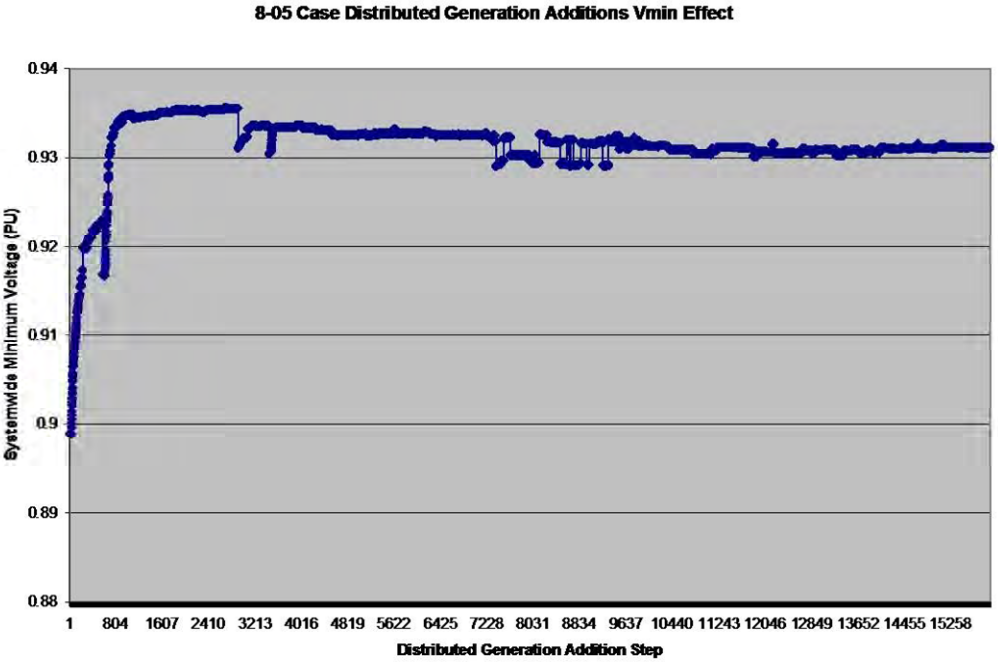

Figure 19. Voltage effect of 2005 summer peak DG additions

The sites of the 1,000 distributed generation projects that are highest-ranked in terms of network benefits lie on just 30 of the 215 Hobby circuits, and about 90% of the capacity that this group of projects represents lies on only 15 circuits.

Together these top 1,000 projects represent 9.05 MW, or an average of about 9 kW per project. The vast majority of these 1,000 projects, 924 to be exact, are residential PV projects. The remaining projects are all small and medium business distributed generation projects comprised of PV projects and smaller distributed generation projects – 11 are over 60 kW and the largest is 221 kW. There are no large industrial projects.

It is interesting to look at the prominence of larger-scale distributed generation in this set. Within full set of 15,945 nominally beneficial distributed generation additions for the 2005 Hobby system, there are 75 large distributed generation projects at industrial customer sites, but individually they are relatively low-ranked in terms of network benefits. The highest-ranked among these is ranked number 1,681, and thus not included in the top-1000 "voltage benefit" group. The largest project in full set of nominally beneficial distributed generation projects is 3 MW. There are five more over one MW and 217 over 100 kW.

Note that under super-peak conditions, the total capacity of the demand response – both existing and added in this case – of nearly 129 MW far exceeds the combined capacity of demand response and distributed generation that showed clear system minimum voltage impacts under normal summer peak conditions. Accordingly, the large volume of demand response capacity the researchers have assumed available under super-peak conditions effectively consumes the opportunities under these conditions to improve the system's absolute lowest voltage using additions of real capacity. Accordingly, the additional benefit to systemwide minimum voltage from additional capacity from distributed generation projects is minimal. This suggests that if demand response were fully developed as a super-peak-only resource, it might go a long way to meeting critical period load reduction needs and provide significant voltage benefits. At the same time, the super-peak period value of other resources such as distributed generation might be quite modest.

Under super-peak conditions, the researchers identified 15,520 distributed generation projects that nominally enhance network performance from 45,477 eligible sites. As a group, these projects increase the systemwide minimum voltage from to 0.935 to 0.937. They also reduce the voltage variability from 0.01468 to 0.0140 but decrease the systemwide median voltage from 1.0106 to 1.00883. The impact of these projects individually on systemwide minimum voltage is highly indirect, and a "voltage benefit" subset is not identifiable. As a group, the 15,520 beneficial distributed generation projects represent 228.648 MW of capacity, or an average of about 15 kW per project. They have no cumulative impact on the system minimum voltage, but reduce P losses from 53.925 MW to 35.650, a reduction of 18.275 MW.

Under 2005 winter peak conditions, the researchers identified 7,988 distributed generation projects that nominally enhance network performance from 45,477 eligible sites. As a group these distributed generation projects increase the system's lowest single-point voltage from 0.919 PU to 0.923, an increase of 0.4 percentage points, reduce the systemwide voltage variability (standard deviation) from 0.0150 to 0.0147 PU, and reduce the system's real (P) losses from 19.120 MW to 13.256, a reduction of 5.864 MW.

These distributed generation additions as a group actually decrease the systemwide median voltage from 1.010 to 1.007, increase the number of buses with voltage under 0.95 PU from 618 to 734, and decrease the systemwide average voltage from 1.007 to 1.004. This is due to the effect of the reactive load of the inductive generators and redispatch of TCULs and capacitors.

The 285 highest-ranked projects in terms of network benefits, taken apart from the others, yield a greater increase in the systemwide minimum voltage, from 0.919 PU to 0.930 PU. This subset of projects also yields a reduction in the number of buses under 0.95 PU from 618 to 586.

As a group the full set of 7,988 beneficial distributed generation projects represent 129.46 MW of capacity, or an average of about 16 kW per project.

Under minimum load conditions, the minimum P Index bus has P Index equal to 0.40. This indicates that every bus in the system is nearly balanced or even slightly surplus in terms of real capacity. Accordingly, under these conditions, there are no demand response or distributed generation projects that can improve network performance through the addition of real capacity.

As indicated above, under off-peak-hour conditions in the 2005 Hobby system, there are some real capacity deficiencies and opportunities to improve network performance through additions of real capacity, unlike under minimum load conditions. In addition, unlike any of the peak conditions evaluated, the many potential PV sites in the system cannot contribute. The researchers identified 858 distributed generation projects that nominally provide network benefits under these conditions. As a group these projects increase the systemwide minimum voltage from 0.9726 PU to 0.9788 PU, they reduce the system's voltage variability from 0.0088 to 0.0081 PU, but they decrease the system's median voltage very slightly from 1.0170 PU to 1.0167 PU.

Essentially all of the improvement in systemwide minimum voltage comes from the 200 or so highest-ranked projects. Because distributed generation adds P capacity (or reduces P load), any increment potentially reduces losses.

The full set of 858 distributed generation projects as a group represents 122.285 MW, or an average of 143 kW per project. The average project size is larger as the group includes no residential PV projects. These projects also represent 17.211 MVAR of Q load due to inductive generators. As a group, these projects reduce P losses from 10.434 MW to 6.614, a reduction of 3.82 MW.

The researchers also identified a set of Optimal DER Portfolio distributed generation projects for the 2011-forecast Hobby system using a similar approach. Figure 20 shows the voltage impact of over 10,500 nominally beneficial potential demand response additions, each added to the system in rank order.

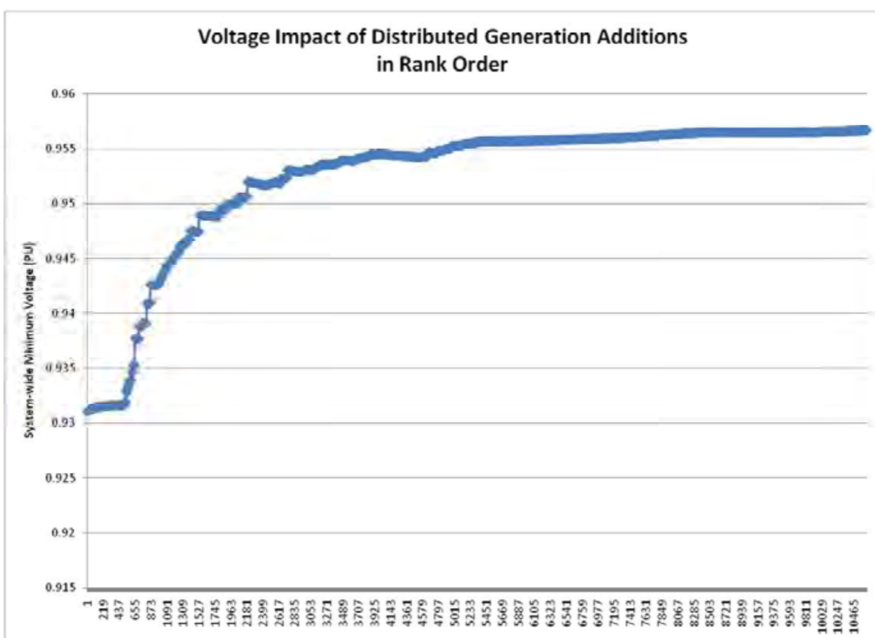

Figure 20. Voltage impact of 2011 DG additions

Again, these projects are all essentially the same in terms of their individual loss impact. It is evident from Figure 20 , coincidentally, that a subset exists of about 3,000 potential distributed generation projects that are “high value” by virtue of their having a disproportionate impact in terms of voltage as measured by their impact on the systemwide minimum voltage. These projects would achieve nearly all of the potential voltage benefit from the entire set of beneficial DG projects.

The 2011 Optimal Portfolio of 3,000 distributed generation additions represents 46.86 MW, or about 2.75% of the Hobby system’s load under these conditions. They lie on 73 different circuits and increase the systemwide minimum voltage by 0.0220 PU or 2.20% of nominal. They would also reduce losses by 5.9438 MW when dispatched under these conditions. Using the project specifications described in Section 2.2.6, this population of projects consists of 83% residential PV projects, 11.4% non-residential PV projects, and 5.6% business and agricultural inductive or synchronous generation projects.

The total capacity represented by the 3,000 Optimal DER Portfolio distributed generation projects represents resource adequacy capacity directly or as reduced peak period load.

In addition, these projects represent incremental capacity to relieve localized loads within the Hobby system provided they are operational, and in the case of the inductive and synchronous units, operating.

Table 25 shows the total capacity of the 2011 Optimal DER Portfolio distributed generation projects, mapped based on their locations to the substations identified previously as capacity deficient in the 2011 Hobby system simulation.

Table 25. DG capacity in loaded substations

Loaded Substation	DG MW
Oyster	
Fish	0.353
Shellfish	
Limpet	
Metal	0.229
Macaw	0.903
Bobwhite	0.238
Tree	6.020
Preventer	0.652
Modjazz	4.653
Weckl	3.927
Sail	7.361
Hawser	0.599
Music	4.927
Paint	1.075
Author	
Bird	7.853
Heron	

Table 25 shows substantial blocks of 2011 Optimal DER Portfolio distributed generation capacity within Tree, Modjazz, Weckl, Sail, Music, Paint, and Bird substations. In terms of load relief, the projects on circuits served from Music substation could provide a deferral benefit. The capacity of the distributed generation projects is more than enough to eliminate the normal-condition overload on Music substation after allowing for planned load shifts. The distributed generation projects on circuits served from Weckl and Metal substations are also enough to eliminate the normal-condition overloads on those substations under forecast loads. However, the overloads on both substations are also relieved through planned load shifts.

Table 26 shows the capacity of the 2011 Optimal DER Portfolio distributed generation projects mapped to the substations whose loading contributes to the elevated reliability risk of the highest-risk circuits in the Hobby system. The distributed generation capacity on circuits served from Bird and Tree substations is insufficient to permit those substations to continue to serve load under a loss-of-bank contingency. However, it could reduce the affected loads on those substations in such an event, assuming the substation remains in service at a reduced level.

Table 26. DG capacity in reliability-risk substations

Loaded Substation Affecting High-risk Circuit	DG MW
Wildcat	0.008
Bird	7.853
Tree	6.020
Fruit	0.068

Storage

As stated in Section 2.2.6, the researchers' approach in identifying the 2005 Optimal DER Portfolio resources was to evaluate the incremental impact of each class of resources with the prior set in place and operating. Accordingly, at the stage where the researchers began assessing storage additions, the 2005 super-peak case was already populated with a very large amount of ideally placed resources. Therefore, the researchers departed from the project's basic approach with storage additions simply to make the impacts of storage additions somewhat more visible. The researchers chose a configuration of the 2005 super-peak-case that included the capacitor additions, the existing demand response, and the 3,000 highest-ranked demand response additions only, with no distributed generation differences. The researchers used the off-peak hour case incorporating the capacitors, demand response, and distributed generation projects identified above.

With these two cases as starting points, the researchers chose to place incremental storage resources at those locations that would receive the highest net benefit from the storage resource on-peak and the storage load off-peak, or those locations with the greatest difference in P Index between the two cases. Again, as stated in Section 2.2.6, the projects' approach with storage was to place a fixed "budget" of distributed storage of 35 MW of nominal on-peak capacity.

The researchers found that the large P Index differences were rarely due to P resource deficiencies under super-peak conditions, and more often due to P resource surpluses under off-peak conditions. This is undoubtedly due in part to the added Optimal DER Portfolio resources alleviating deficiencies under super-peak conditions.

As noted in Section 2.2.6, the researchers did not set upper limits on storage additions. However, the researchers did find that the *minimum* size for storage addition increments had a significant effect on how the portfolio of projects looks. In the absence of a minimum storage increment size, the portfolio of additions under the GRIDfast™ process is a huge number of very small additions, though with multiple increments (or larger "project" sizes) at a single location. To make the portfolio more realistic, the researchers imposed a minimum size for storage addition increments initially of 60 kW.

The researchers identified and ranked 493 storage "project" sites on 82 different circuits that yield net network benefits under this projects approach. Of these storage additions, most were composed of a single 60 kW increment. However, 54 were larger projects with multiple 60 kW increments, with the largest 360 kW.

A relatively small number of circuits received high concentrations of storage additions, with total storage capacity additions on a single circuit greater than 700 kW. These are:

- Calla o/o Flower12 kV
- Gladiolus o/o Flower 12 kV
- Lily o/o Flower 12 kV
- Carnation o/o Flower 12 kV
- Daffodil o/o Flower 12 kV
- Leopard o/o Wildcat 12 kV
- Panther o/o Wildcat 12 kV
- Tiger o/o Wildcat 12 kV
- Cadmium o/o Metal 12 kV
- Nickel o/o Metal 12 kV
- Chromium o/o Metal 12 kV
- Clarkey o/o Fish 12 kV
- Shorter o/o Weckl 12 kV/Modjazz 33 kV
- Towhee o/o Macaw 12 kV/ Bird 33 kV

Under super-peak conditions, these 493 storage projects yield identifiable network performance benefits. They reduce voltage variability slightly from 0.0171 to 0.0170 PU. Noting that GRIDfast™ is attempting to optimize to a voltage range that allows some pretty low voltages, there is little change to the systemwide minimum voltage, but the systemwide maximum voltage decreases from 1.050 to 1.044 PU, and the median voltage moves closer to 1.0 PU, from

1.0089 to 1.0080 PU. These projects also result in a loss reduction under super-peak conditions of 62.53 MW to 57.88 MW, or 4.65 MW.

As the peak-period voltage benefits of these projects appear less significant than the loss benefits, this may indicate that with the relatively wide voltage limits set for the optimization with the starting point the researchers chose there is little opportunity to "improve" voltage within those limits with P capacity additions.

Under off-peak conditions, the researchers would expect any storage scenario to increase loading and losses and possibly impair voltage. In fact, with this set of storage additions, the researchers found that the systemwide minimum voltage under off-peak conditions fell from 0.9788 to 0.9695 PU, and losses increased from 6.61 MW to 8.40 MW.

Significantly, the researchers also found that the system's real power deficiency under off-peak conditions was dramatically increased in some locations, as indicated by a more negative P Index. Overall the area's average P Index decreased from -0.05 to -0.69 due to the storage loads. The following areas now had off-peak P indices lower than -2.0:

- Sextant
- Cleat
- Plank
- Loon
- Cormorant
- Carter

Most significantly, in certain locations on Cormorant circuit, the P index under off-peak conditions was lower than -1,400. The voltage on these circuits does not reveal this deficiency. Under these off-peak conditions, Cormorant contains the system's lowest voltage buses. However, the lowest voltage bus on the circuit is still 0.969 PU, and the voltage at the substation (as might be reported from field monitoring) is still over 1.01 PU.

It appears that this effect is the result of the placement of the storage devices on these circuits or on nearby circuits. None of these stressed circuits are among those circuits listed above that received a high concentration of storage capacity additions, even though Cleat and Cormorant were identified above as carrying a high difference in P index between super-peak conditions and light load conditions. Sextant and Loon received no storage additions, and the others generally received a single 60 kW project. Carter received four 60 kW projects at different locations.

It is probably significant that these circuits are all part of substation systems served from other distribution circuits and are thus exposed to double transformation.

This suggests that even relatively small storage devices – in this case as small as 60 kW – placed in locations in the power system where they would appear to yield high net benefits (that is, considering both the off-peak *and* on-peak impacts) can introduce significant stress in those locations as they recharge.

To test this finding, the researchers ran a second case setting 10 kW as the minimum size for storage additions. This smaller size would permit more distributed placement of storage devices. Under the assumptions discussed above, each 10 kW storage increment would have a charging load of 12.5 kW. This is an arguably consistent size with household storage devices such as electric vehicles in vehicle-to-grid (V2G) applications.

The researchers identified 1,488 storage sites on 93 different circuits that yield net network benefits. These storage additions are actually made up of 3500 rank-ordered 10 kW additions. Individually most of the storage projects under this set of assumptions are made up of single 10 kW increments; the largest is 60 kW.

The circuits receiving the greatest total storage capacity are essentially the same as in the 60 kW case above, and in most cases in very similar total amounts. In effect, these storage projects are allocated to circuits similar to the 60 kW storage projects, but their capacity (and charging load) is more distributed within each circuit.

Under super-peak conditions, these storage projects yield identifiable results. They reduce voltage variability from 0.0171 to 0.0168 PU, increase systemwide minimum voltage from 0.9187 to 0.9189 PU, decrease systemwide maximum voltage from 1.050 to 1.042 PU, and the median voltage moves closer to 1.0 PU, from 1.0089 to 1.0085 PU. Compared to the 60 kW additions, these storage projects reduce voltage variability more, 0.0168 compared to 0.0170 PU; they result in a higher systemwide minimum voltage, 0.9189 compared to 0.9181; they decrease systemwide maximum voltage more, 1.042 compared to 1.044. The systemwide median voltage for the 60 kW additions is slightly closer to 1.0, 1.0080 vs. 1.0085. These projects also result in a loss reduction under super-peak conditions of 62.53 MW to 58.01 MW, or 4.52 MW, slightly less than the peak loss reduction from the 60 kW additions.

Under off-peak conditions, with these units charging, the storage additions in 10 kW increments result in slightly less reduction in the systemwide minimum voltage and result in less loss increase compared to the 60 kW storage case. Under off-peak conditions with storage charging, the researchers found the systemwide minimum voltage fell from 0.9788 to 0.9773 PU (compared to 0.9695 PU for the 60 kW storage additions), and losses increased from 6.61 MW to 8.29 MW (compared to 8.40 MW for the 60 kW storage increments).

More importantly, with these units based on 10 kW increments in place for their charging, there are fewer areas with marked real power deficiency under off-peak conditions and the impact is less extreme. The only regions with P indices lower than -2.0 under off-peak conditions are Cormorant and Carter circuits. Further, the P index values within Cormorant and Carter are much more acceptable; Carter has the lowest P Index points off peak, and the lowest points on that circuit have P indices of about -2.47.

This shows that smaller, more distributed storage additions have less adverse impact off-peak during charging. It suggests that there is a size of storage increment between 10 kW and 60 kW, below which these units can be sited for their maximum net on-peak and off-peak benefit with reduced or no risk of stress to the system off-peak due to the charging load.

Enhancing the results of these findings, the researchers ran a third case, retaining 60 kW as the minimum size for storage additions, but restricting the storage sites to those locations that could accommodate the charging load-off peak. This would necessarily reduce the ability to site these resources for their best net on-peak and off-peak benefit but might avoid adverse system stress off-peak.

The researchers identified 354 storage sites on 80 different circuits that yield net network benefits. Again, the circuits receiving the greatest total storage capacity are essentially the same as in the unrestricted 60 kW case above. Individually the majority of these projects are 60 kW. Researchers found 112 projects have multiple increments of additions (i.e. totaling 120 kW or more); the largest are 9 projects totaling 360 kW. Therefore, these projects are allocated to circuits similarly to the 60 kW projects in the unrestricted case but are in fact less distributed than the 60 kW projects in the unrestricted case.

These storage projects yield identifiable voltage benefits under super-peak conditions. They reduced voltage variability slightly from 0.0171 to 0.0168 PU. They actually lower the systemwide minimum voltage from 0.9187 to 0.9152 PU. They decrease systemwide maximum voltage from 1.050 to 1.045 and the median voltage moves closer to 1.0 PU: from 1.0089 to 1.0082 PU.

Compared to the earlier, unrestricted 60 kW additions, these storage projects are not as effective in terms of network benefits under on-peak conditions. They reduce voltage variability essentially the same amount, but they result in a lower systemwide minimum voltage, 0.9152 PU compared to 0.9180 U, and they decrease systemwide maximum voltage less, 1.045 PU compared to 1.044 PU. The systemwide median voltage for the unrestricted 60 kW additions is also slightly closer to 1.0 PU: 1.0080 PU vs. 1.0082 PU.

Compared to the 10 kW additions, these storage projects are also not as effective. They reduce voltage variability essentially the same amount, but they result in a lower systemwide minimum voltage, 0.9152 compared to 0.9189 PU, and they decrease systemwide maximum voltage less, 1.045 PU compared to 1.042 PU. However, the systemwide median voltage for the 60 kW additions though restricted is slightly closer to 1.0 PU; 1.0082 vs. 1.0085 PU.

These projects also result in a loss reduction under super-peak conditions of 62.53 MW to 57.92 MW, or 4.61 MW, slightly less loss reduction than the unrestricted 60 kW additions, but a slightly greater loss reduction than the 10 kW additions.

So while the differences are very small, these results show measurably that the 60 kW storage device additions, when restricted by location, provide less voltage benefit under peak conditions than either the unrestricted 60 kW additions or the 10 kW additions. This is probably because the citing restriction prevents placement of these units' capacity for its best advantage on-peak.

The storage additions in 60 kW increments and at restricted sites as charging loads, result in slightly less reduction in the systemwide minimum voltage and less loss increase under off-peak conditions compared to the 60 kW unrestricted storage case. Under off-peak conditions the researchers found the systemwide minimum voltage fell from 0.9788 to 0.9736 PU (compared to 0.9695 PU for the 60 kW unrestricted storage additions), and losses increased from 6.61 MW to 8.31 MW (compared to 8.40 MW for the 60 kW unrestricted storage increments). Under off-peak conditions the only region with P indices under -2.0 with these 60 kW storage units in place is Carter circuit, and the lowest point on Carter has a P index of about -2.25. Again, the P indices are acceptable.

This suggests that siting restrictions are an effective way to mitigate the potential off-peak impacts of larger storage units, and that in this case, with these restrictions, the larger 60 kW storage devices may be accommodated.

A closer look at the individual storage addition steps and projects lends support to these conclusions. Where 60 kW storage addition increments are unrestricted, the second storage addition step is the one that causes the most extreme systemwide off-peak P index to drop to extremely negative values. This particular storage addition is in Cormorant circuit, the circuit where the most extreme off-peak P indices also occur. When the sites for these 60 kW additions are restricted, no storage is added to this circuit, and the off-peak P index remains acceptable. When the minimum storage additions are set to 10 kW, a 10 kW increment is added in this circuit at this site, a second 10 kW increment is added at a different site on the same circuit, and the off-peak P index remains acceptable. Therefore, in this instance adding storage in smaller and more distributed increments can mitigate off-peak P stress.

Figure 21 illustrates the same phenomenon in voltage terms and storage in 10 kW increments. The off-peak voltage profile of a particular path on Loon and Cormorant circuits is shown with no storage additions and after the addition of four 10 kW storage increments systemwide. Initially the off-peak voltage actually increases along the path at the Penguin substation and out the Cormorant circuit. With the introduction of the storage devices and their charging load, the voltage at the end of Cormorant drops down to a barely acceptable 0.95 PU.

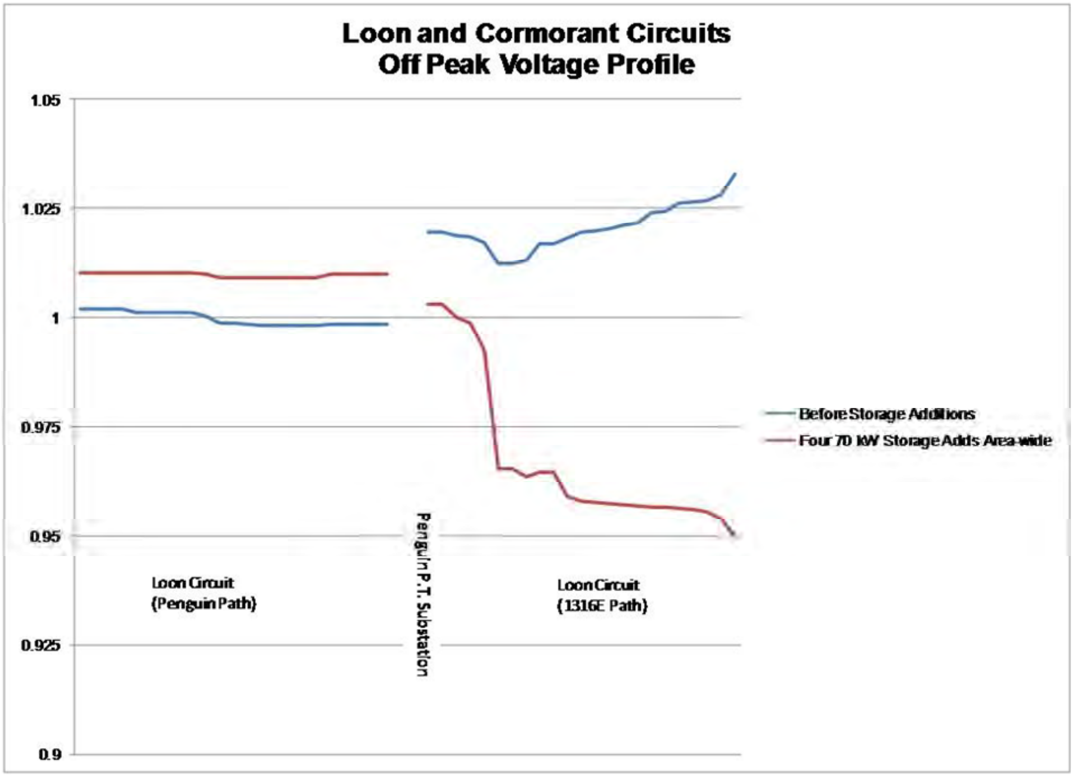

Figure 21. Off-peak voltage impacts of storage additions – Cormorant circuit

The foregoing study on storage was intended more to understand and test the bounds of potential P stress off-peak from storage projects. Based on this analysis, for the Hobby system the optimal DER storage projects consist of 1,488 storage sites on 93 different circuits totaling approximately 35 MW of on-peak capacity. These projects range in size from 10 kW to 60 kW; the majority are 10 kW projects.

These projects' capacity would be available under peak and super-peak conditions, and they would recharge at a rate of 1.25 times their rated capacity under off-peak conditions.

These storage projects comprise approximately 3,500 individual 10 kW storage increments. The 230 highest-ranked projects among these yield the greatest voltage benefit, as shown below. Stated in project terms these 230 additions lie on 119 individual buses on 26 circuits. Off-peak, as charging loads, the 1,488 projects increase losses and reduce voltage, but the researchers have shown that they do not produce high levels of stress.

The circuits with the greatest concentration of ideally placed storage projects are listed in Table 27.

Table 27. Circuits with high storage project concentrations

Circuit	Parent Substation	Storage Projects	Storage (MW)
Lily	Flower	46	1.93
Calla	“	48	1.88
Nickel	Metal	38	1.70
Leopard	Wildcat 12 kV	52	1.55
Carnation	Flower	31	1.24
Gladiolus	Flower	56	1.22
Tiger	Wildcat 12 kV	36	1.09
Panther	“	58	1.06
Clarkey	Fish	33	94
Blanket	Ride	29	0.89
Daffodil	Flower	37	0.84
Shorter	Weckl/Modjazz	50	0.83
Chromium	Metal	34	0.79
Cadmium	“	30	0.72
Platinum	“	30	0.69
Basenji	Dog	30	0.65
Towhee	Macaw	27	0.58
Sprint	Polo	24	0.58

Reliability Impacts of DER Additions

It is important to reiterate that the Optimal DER Portfolio projects described above are defined using an optimization/ranking approach designed primarily to reduce losses and voltage deviation. In contrast, the reliability assessment methodology the researchers demonstrated in this project is driven by loading and the interplay of loading and topology. Accordingly, the nominal reliability benefits of the Optimal DER Portfolio projects are somewhat of an indirect result. An alternative optimization/ranking approach could focus entirely on DER projects sited and operated to provide load relief with meaningful reliability benefits. This approach is incorporated in Reliability Optimization below. Having said that, the results and findings here demonstrate a rigorous, objective approach to assessing the reliability impacts of a set of projects that is relevant under either approach.

The researchers evaluated the impact of the 2005 Optimal DER Portfolio Projects on reliability through two mechanisms – load relief opening additional post-contingency load shift opportunities and load relief reducing otherwise elevated failure risk. For DER capacity to *improve* reliability by opening up additional post-contingency load shift opportunities, the researchers viewed that two conditions must be met. First, the DER capacity must provide enough load relief to move a circuit from ineligible to eligible to accept load shifts. Second, the relieved circuit must serve as a backup to another circuit having compromised load shift opportunities.

The researchers found that distributed generation projects on two circuits represented sufficient capacity to open those circuits to post-contingency load transfers and in doing so, enhance post-contingency load transfer opportunities of "sibling" circuits that otherwise would have compromised load transfer options. In each case, the impacts would occur under normal summer peak conditions. The researchers found that demand response projects on four circuits represented sufficient capacity to open those circuits to post-contingency load transfers and also, in doing so, enhance post-contingency load transfer opportunities of "sibling" circuits otherwise having compromised load transfer options. In each case, the impacts would occur under super-peak conditions only. Because super-peak conditions represent such a small share of the operating year, the overall impact on reliability in annual terms of the demand response projects on these four circuits is much smaller.

Of the circuits with line segments loaded at over 120% of normal rating under one or more operating conditions, only Peach had enough demand response capacity to eliminate the condition, under super-peak conditions. Again, because this benefit occurs under a small share of the operating year, the measured overall impact of the Peach circuit demand response projects on reliability is small.

Table 28 and Table 29 show the circuits of each of these sets of DER projects, the circuits whose reliability they affect (through expanded post-contingency load transfer opportunities), and the annual reliability impact of these DER projects. The reliability impact is expressed as the change in expected outage hours, the change in expected unserved energy in kWh terms, and the change in expected unserved load in value of service terms.

Table 28. Load shift benefits of 2005 Optimal DER Portfolio projects

Circuit DG Projects	Affected Circuit(s)	Outage Impact (h/yr)	Un-served Load Impact (kWh/yr)	Impact in VOS ($/yr)
Blanket	Ketch	.72	7,027	$52,927
Net	Towel	1.10	10,185	$37,515
Spur	Bit	.01	128	$513
Chromium	Copper	-	41	$372
Apple	Peach, Pear	.07	636	$2,362
Lynx	Tiger, Wildcat	.03	307	$3,167

Table 29. Overload reduction benefits of 2005 Optimal DER Portfolio projects

Circuit DR Projects	Outage Impact (h/yr)	Un-served Load Impact (kWh/yr)	Impact in VOS ($/yr)
Peach	-	66	$200

It is evident that when reliability is measured in terms of unserved hours or kWh per year, DER measures having a material impact during a significant share of the year, such as during all normal summer peak hours, emerge as having a much greater nominal reliability benefit. The two circuits whose posited reliability is most improved, Ketch and Towel, are among those in

Hobby with relatively high overall expected outage risk, in large part due to the insufficient post-contingency opportunities of those two circuits. Optimal DER Portfolio DG projects on Blanket and Net, respectively, open up needed post-contingency load shift capacity for Ketch and Towel under all normal summer peak hours. Thus, the expected unserved load risk on Ketch and Towel is reduced, and the reliability impact attributable to the DG projects on Blanket and Net is material. In the case of the Blanket and Ketch circuit DG projects, just the improvement in the interruption risk they provide for their affected circuits is greater than the average interruption risk for the system as a whole.

The researchers also analyzed the 2011 Optimal DER Portfolio demand response and distributed generation projects on individual circuits for their impact on circuit loading as it affects reliability. There is Optimal DER Portfolio capacity on seven circuits with segments loaded at greater than 120% of their normal ratings, the level at which the researchers assume a reliability impact. However, of these, only relief on Mussel circuit would have a quantifiable impact on reliability. The other circuits have sufficient alternate sources that they do not have reliability risk under this project's rubric. The total reliability impact of the DER capacity on Mussel circuit in terms of circuit overload relief, shown in Table 30, is a 497 kWh/yr reduction in expected unserved load.

There are 42 circuits with Optimal Portfolio DER capacity that serve as alternate sources for circuits with constrained load shift opportunities and that are loaded to where they are not available to take post-contingency load shifts. Load relief on these circuits in principle should have a reliability benefit. Excluding those circuits with very small amounts of total DER capacity in the portfolio and those for whom the reliability impact is small, the researchers identified 25 circuits whose DER projects that would yield a meaningful reliability impact in term of reduction in expected unserved kWh per year by expanding post-contingency load shifts, or, in one case relieving a circuit overload. These results are listed in Table 30.

Table 30. 2011 Optimal DER Portfolio reliability benefits

Measure	Circuit Overload Relief (kWh/yr)	Load Shift Opportunity (kWh/yr)
Sloop Ckt DER Projects		33,609
Yawl Ckt DER Projects		48,202
Wrasse Ckt DER Projects		46,364
Barbera Ckt DER Projects		8,781
Muscat Ckt DER Projects		23,259
Riesling Ckt DER Projects		39,258
Roan Ckt DER Projects		31,586
Rich Ckt DER Projects		10,332
Cadmium Ckt DER Projects		20,128
Chromium Ckt DER Projects		32,008
Brecker Ckt DER Projects		30,784
Carter Ckt DER Projects		20,496
Flute Ckt DER Projects		7,398
Guitar Ckt DER Projects		20,234
Trombone Ckt DER Projects		26,587
Smock Ckt DER Projects		57,654
Watercolor Ckt DER Projects		51,531
Exclusion Ckt DER Projects		16,411
Bridle Ckt DER Projects		7,318
Saddle Ckt DER Projects		51,603
Spur Ckt DER Projects		46,869
Dinghy Ckt DER Projects		36,026
Mussel Ckt DER Projects	497	16,182
Cedar Ckt DER Projects		28,961
Panther Ckt DER Projects		15,324

These 25 circuits lie in and enhance load-transfer opportunities in the following 15 systems:

- Boat
- Fish
- Grape
- Horse
- Jazz
- Metal
- Modjazz
- Music
- Paint
- Polo
- Ride
- Sail
- Shellfish
- Tree
- Wildcat

The 2011 Optimal DER Portfolio projects do not have sufficient aggregate capacity within any substation to permit that substation to operate through a loss-of-largest transformer bank contingency, thus they do not reduce any circuits' risk of unserved load due to a transformer contingency.

3.2.7. Reliability Optimization

As stated in Section 2, in this portion of the study, the researchers sought to develop and demonstrate a methodology that would use GRIDfast™ and the Energynet® model to show ways to improve system reliability through principally the following means:

- Reduced impacts of given contingencies.
- Enhanced post-fault restoration (reducing outage time).
- Identification of demand response and distributed generation capacity additions with specific benefits in reducing the impacts of given contingencies or enhance post-fault service restoration.

For this portion of the study, the researchers considered initially one contingency in the 2005 Hobby system, referred to as "Outage #1." Outage #1 is a transformer outage that would affect 1,782 buses representing approximately 37,456 kW of load under normal summer peak conditions. For this block there are 16 tie switches connecting to alternate sources. Again, the objective was to find ways to reduce the impact of this outage (and the others considered here) possibly with optimized system configuration under contingency conditions or with DER additions.

Restoration following Outage #1 via a single switch closure would minimize the impact of this outage on customers. In evaluating restoration following Outage #1 via a single switch closure alone, with no other measures, across a variety of operating conditions, the researchers found four switches that could be closed under any conditions without collapse and three that could not be closed under any conditions. Note that in the reliability assessment above, the researchers considered a path to an alternate source as "available" if the destination circuit loaded at less than 65% of its emergency rating, and where the posited load shift would be a partial circuit. Here the researchers consider a path to an alternative source as "available" at least initially simply considering whether it can accept a large load shift (in this case the entire affected load block) in a feasible power flow simulation that will converge to a solution. Under off-peak conditions, the least demanding, the post-closure drop in voltage at the point of connection ranged from 1.3% to over 14%; in the case of 6 of the 13 "feasible" switches, the voltage drop was less than 10%. Under super-peak conditions, the most demanding, the post-closure voltage drop at the point of connection was less than 10% for each of the four "feasible" connections.

The researchers next evaluated restoration following Outage #1 via a single switch closure with the benefit of optimization using GRIDfast™ . Specifically, the researchers used GRIDfast™ to re-optimize the system under each post-contingency switch closure to see if this would make available more single-switch restoration choices, arguably enhancing reliability. In this case, the researchers implemented recontrols with flow minimization incorporated directly into the optimization objective function, along with voltage deviation minimization. This is a departure from the objective function used in the other tasks in this project.

The researchers found that the same switches could be closed with feasible power flow solutions under any operating conditions, and the same three could not be closed under any conditions, even with the benefit of GRIDfast™ post-contingency optimization.

The researchers did find that, under off-peak conditions with GRIDfast™ optimization, the number of switches among the 13 "feasible" switch closures with post-closure voltage drops of less than 10% increased from six to nine. Under super-peak conditions, the four "feasible" switch closures still had post-closure voltage drops of less than 10% with GRIDfast™ optimization. Thus, post-contingency optimization using GRIDfast™ had a slight beneficial impact on the available single-switch restoration options.

Having assessed "feasibility" in a power flow sense, the researchers next looked at the substation overload ramifications of single-switch restorations for Outage #1. To reiterate, in the reliability assessment above, the researchers considered an alternate feed as available to accept a partial-circuit load shift if no individual segments of the serving circuit are loaded at greater than 65% of their emergency ratings. Earlier the researchers had considered an alternate feed as available to accept the entire load block through a single switch closure if the post-contingency configuration would converge in a power flow solution. Now the researchers assessed these alternate feeds in terms of the loading on the transformer taking on the shifted load as well.

Under normal summer peak conditions, slightly less demanding than super-peak conditions, the researchers found that of five nominally feasible single-switch restorations for Outage #1 that could be completed without collapse, all did cause an overload of the transformer serving the receiving circuit. Under off-peak conditions, four of the seven of the nominally feasible single switch restorations for Outage #1 would result in overloads of the receiving transformer.

Because Outage #1 impacts such a large load block, the researchers considered other outages, referred to as Outage #3, Outage #4, and Outage #5. These are also transformer bank outages, but smaller banks affecting less connected load. Outage #4 affects only one circuit, while Outage #3 affects two circuits, and Outage #5 affects three circuits.

Under normal summer peak conditions the researchers found that there is one single-switch restoration for Outage #3 that results in a "feasible" power flow solution, but that also results in overload of the receiving transformer. The researchers found that there are nine nominally feasible single-switch restorations for Outage #4, none of which overloads the receiving transformer. For Outage #5 the researchers found 15 nominally feasible single-switch restorations, one of which results in an overload of the receiving transformer.

The researchers found that under off-peak conditions all of the nominally feasible single-switch restorations for Outages #3, #4, and #5 could be implemented without overloading the receiving transformers. However, of the seven nominal feasible single-switch restoration of Outage #1 under off-peak conditions, all but three would result in an overload of the receiving transformer.

The researchers next considered the potential benefits from DER additions in either opening up more "feasible" single-switch post-contingency restorations or in mitigating overloads of receiving transformers under post-contingency load shifts, where these overloads would otherwise occur. The researchers considered both demand response (DR) and distributed generation (DG), using the same DR and DG citing criteria and limitations described in Section 2.2.6. However, in this case, the researchers identified and ranked DR and DG additions explicitly based on their ability to relieve overloads, with minimization of flow exceeding rated capacity again incorporated directly into the optimization objective function.

The researchers found that under summer peak conditions and Outage #1, DR, and DG additions under the limits of this project's rubric could not overcome the transformer overloads that would result from any of the single-switch restorations. The researchers also found that with Outage #3 DR additions did not represent enough capacity to relieve the expected load-shift transformer overloads. However, the researchers did find that with ideally placed DG, the one feasible single switch restoration could be implemented without overloading of the receiving transformer.

The researchers also found that under off-peak conditions, ideally placed DG would mitigate the overloads posited for single-switch restoration of Outage #1. Again, the researchers found that DR would not provide enough capacity to relieve these overloads. Therefore, through this the researchers have identified specific DG projects that, in addition to their other benefits, also as a group provide the benefit of creating a single-switch restoration option for Outage #3 under normal summer peak conditions, yielding a specific reliability benefit. There is another set of DG projects with the added benefit of expanding the single-switch restoration alternatives for Outage #1 under off-peak conditions, again, yielding a specific reliability benefit.

Table 31 summarizes these results. The term "nc" means the addition of DG did not affect the available single-switch restorations.

Table 31. Summary of reliability optimization results

	Summer Peak			Off-Peak		
Outage	**"Feasible" Single-Switch Restorations**	**Without Overload**	**No Overload with DG**	**"Feasible" Single-Switch Restorations**	**Without Overload**	**No Overload with DG**
#1	5	-	-	7	3	7
#3	1	-	1	3	3	nc
#4	9	9	nc	9	9	nc
#5	15	14	nc	15	15	nc

Table 32. Restoration switches

Summer Peak			Off-Peak		
Outage	Switch		Outage	Switch	
#3	PS1696		#1	PS1548	
#3	PS1330		#1	PS1458	
#3	PS0010		#1	PMH1824	
#3	PS0135		#1	PS1132	with DG only
#3	4458922ET		#1	GS2892	with DG only
#3	PS1731		#1	GS2892	with DG only
#3	GS5028		#1	PMH1921	with DG only
#3	RCS1523		#3	PS1696	
#3	GS5942		#3	PS1330	
#3	OS1222		#3	PS0010	
#3	GS5943		#3	PS0135	
#3	PS1706		#3	4458922ET	
#3	12160S		#3	PS1731	
#3	GS6003		#3	GS5028	
#4	GS1244	with DG only	#3	RCS1523	
#5	GS5511		#3	GS5942	
#5	GS5846		#3	OS1222	
#5	PS1970		#3	GS5943	
#5	GS5833		#3	OS1220	
#5	GS5531		#3	PS1706	
#5	GS4290		#3	12160S	
#5	PME5499		#3	GS6003	
#5	GS5529		#4	GS1073	
#5	GS5532		#4	RCS1551	
			#4	GS1244	
			#5	GS5511	
			#5	GS5846	
			#5	PS1970	
			#5	GS5833	
			#5	GS5531	
			#5	GS4290	
			#5	PME5499	
			#5	GS5529	
			#5	GS5532	

Table 32 lists the individual switches that would be involved in the achievable single-switch restorations for each of the outages considered. In light of the ability of these 33 switches to restore entire load blocks with a single closure, these might be excellent choices for remote operation.

In summary, these results identify a set of restoration actions for several outages, under both peak and off-peak conditions that may be implemented with a single switch while not violating transformer loading limits, permitting the fastest, simplest service restoration. The researchers have also identified a group of DG projects that enable or enhance these restorations for specific contingencies.

Single-switch restoration of a load block following a contingency is arguably an extreme approach for service restoration in a system lacking designed-in surplus capacity for that purpose. It has the benefit, however, of the minimum number of steps to restore affected customers. Therefore, it may be appealing where possible, particularly following transformer bank outages that may otherwise require many switching steps to redistribute affected load. Through the process illustrated here the researchers were able to identify single-switch restorations that would not result in an infeasible power flow solution or a transformer overload condition for several of the outage scenarios and under both on-peak and off-peak conditions. GRIDfast™ optimization of existing controls with a load-minimizing component in the optimization objective function did not meaningfully affect the single-switch restoration opportunities. However, DG additions identified based on a GRIDfast™ analysis incorporating load minimization in the objective function did expand single-switch restoration opportunities in boundary cases such as Outage #3.

3.2.8. Substation and Circuit Expansion Projects

The researchers considered and modeled the following specific projects from the Hobby system capital plan, listed by their planned year of implementation:

1. 2010: Caravel Circuit out of Boat 12 kV (redistributes load among Boat substation circuits by removing load from Sloop and Catboat circuits).
2. 2010: Starling Circuit out of Macaw substation (redistributes load on Macaw substation circuits by reducing load on Woodpecker circuit, and reduces load on Metal substation by shifting load from Platinum circuit).
3. 2010: Container Substation; takes over circuits from Limpet, reducing load on Shellfish 115/33 substation
4. 2010: Fastener Substation; takes over circuits from Bobwhite, reducing load on Bird 115/33 substation
5. 2010: Macaw Substation uprate to 115/12; reduces load on Bird 115/33 substation
6. 2012: Cloud Substation; takes over circuits from Preventer, reducing load on Sail 115/33 substation

7. 5 yrs: Oyster Substation uprate to 115/12; reduces load on Shellfish 115/33 substation
8. 10 yrs: Weckl Substation uprate to 115/12; reduces load on Modjazz 115/33 substation

The researchers evaluated the impact of each of these projects individually on the Hobby system under 2011 forecast loads by comparing results with the base 2011 forecast simulation described in Section 3.2.1. The results are provided in Table 33. Vmin improvement is the change in the systemwide minimum voltage resulting from each project relative to the forecast case with no changes, expressed in terms of percentage points of nominal voltage

Table 33. Voltage and loss impacts of network expansion projects

Project	Vmin Improvement	P Loss Reduction (MW)
Caraval Ckt	0.00%	0.0743
Starling Ckt	0.01%	-0.1718
Container Sub	-0.01%	1.8599
Fastener Sub	-0.01%	3.0390
Macaw Sub	0.47%	1.8622
Cloud Sub	0.16%	1.6873
Oyster Sub	-0.07%	0.2003
Weckl Sub	0.42%	3.4149

In each case, the performance of the system with each project is shown with optimized controls, and the impact is shown relative to the base results with optimized controls. The Macaw, Weckl, and Cloud substation projects have the greatest impact on the systemwide minimum voltage, while Weckl, Fastener, Macaw, Container, and Cloud substation projects have the greatest real power loss benefit. Table 34 lists the impact of each project on the loading of substations identified above as requiring load relief. All of the projects except Caravel eliminate the normal-condition overload in at least one substation. The Container substation project relieves Limpet and Metal, but its own capacity is overloaded under the forecast caseloads.

Table 34. Network expansion projects capacity impacts

Project	Substation OL Relief	Substation Emergency Relief
Caraval Ckt	-	
Starling Ckt	Metal	
Container Sub	Limpet, Metal	
Fastener Sub	Bobwhite	
Macaw Sub	Bird	Macaw
Cloud Sub	Sail, Preventer	Cloud (Preventer)
Oyster Sub	Oyster	Oyster, Shellfish
Weckl Sub	Weckl	Weckl, Modjazz

It is worth noting that planned load shifts identified in the Hobby capital plan would resolve the forecast overload of Weckl 12 kV as well as Metal 12 kV. In addition, transformer bank additions proposed at Music 12 kV, Paint 12 kV, and Heron 12 kV would resolve the overloads at those substations. Table 34 also identifies for each project "substation emergency relief," or any substations relieved by that project to where the substation has sufficient capacity to serve its load with the loss of its largest transformer bank. The Oyster and Weckl substation voltage uprate projects provide this margin for themselves, also Shellfish, and Modjazz substations, respectively. The Macaw and Cloud substation projects provide this margin only for themselves. However, when the researchers incorporate the results of the reliability study to assess the incremental reliability benefits from this additional capacity, the researchers see that none of these substations is a contributor to the very high-outage-risk circuits noted in the 2011 Hobby system reliability assessment above. Further, only Macaw substation's circuits have significant exposure to unserved load due to a transformer bank failure. The Cloud substation project takes over the circuits presently served by Preventer substation, which also has exposure to unserved load due to a transformer bank failure. Circuits served from the Shellfish and Modjazz substations have minimal risk, and Oyster and Weckl have no risk, in all cases due to the availability of alternate feeds.

Table 35 shows for each of these projects the impact on reliability risk, in terms of reduced risk of customer outages in kWh/year terms, due to the expanded post-contingency operation capabilities of these transformers.

Table 35. Network expansion projects reliability impacts

Project	Substation Emergency Relief (kWh/yr)
Caraval Ckt	
Starling Ckt	
Container Sub	
Fastener Sub	
Macaw Sub	23,499
Cloud Sub	4,139
Oyster Sub	
Weckl Sub	1,402

3.3. Ranking/Benefit-Cost Analysis

Two of the core research goals of the project were to demonstrate the additional capabilities of the methodology beyond idealized placement of DER and to demonstrate the practical value of the methodology to users, specifically the methodology's ability to enhance power delivery, network decision-making, and problem-solving. The previous Section 3.2 and the following Section 3.3 together fully address these goals.

Section 3.2 demonstrated evaluations of a wide range of potential network performance enhancement measures using the methodology. DER placement is included, but there are others, including traditional substation and circuit expansion projects.

Section 3.3 extends the evaluation of these measures to how they address specific operational objectives and their economic value. In particular, Section 3.3 discusses the impact of each of the network performance improvement measures in terms of each of the network benefit categories, in every case expressing the results in $/year terms that allow direct comparison of the benefits of each measure with the others.

3.3.1. Hobby System Operational Objectives

In Section 2.2.3 the researchers identify the addressing of identified system operational needs as one measure of the value of a given network enhancement measure.

The researchers identified a specific set of operational and planning objectives for the 2011 Hobby system from the SCE capital plan for the system, the researchers' simulation of the system with 2011 loads but no other changes, and the researchers' reliability assessment of the system simulated with 2011 loads. These operational or planning objectives are listed in the Section 2.2.3.

The 2011 Hobby system's identified substation load relief needs could be addressed as follows:

- For the Music substation, load relief could be provided from the proposed networking switch closures or from the capacity of the Optimal DER Portfolio demand response and distributed generation projects on circuits served from the Music substation. A transformer bank addition proposed in the Hobby system capital plan could also address this need.
- Load relief for the Paint substations could be provided from the proposed networking switch closures. There is insufficient DER capacity in the Optimal DER Portfolio to provide the needed load relief for the Paint substation. Load relief for the Paint substation would also be provided from the transformer bank addition proposed in the Hobby system capital plan.
- Load relief for the Heron substation would be provided from the transformer bank addition proposed in the Hobby system capital plan.
- The Macaw substation project would provide load relief for the Bird substation.

None of the measures proposed provides sufficient relief for Author, Boat, Fish, or Hawser substations to eliminate their normal-condition overloads.

In terms of substation load relief to address high-reliability risk circuits, none of the measures provides sufficient relief for the Wildcat, Bird, Tree, and Fruit substations to permit them to continue to serve load with the outage of their largest bank and to yield a reliability benefit for the circuits with the greatest reliability risk. A transformer bank addition proposed in the Hobby system capital plan would provide this capability for Fruit substation. Optimal DER Portfolio DR and DG projects could meaningfully reduce the potentially unserved load on Wildcat, Bird, and Tree substations in the event of such a contingency, assuming the substation remains in service at a reduced capacity level.

The foregoing analysis shows that the system's identified voltage improvement needs would be met through ideal dispatch of existing transformer taps, station and line capacitors, and the

VAR output of existing distribution-connected generation, with the exception of voltage improvement needs for the Horse 12 kV system.

In terms of identified load redistribution needs, the proposed set of networking steps would provide load distribution on circuits served from the Metal substation, as would the Starling circuit project. The Caravel and Starling circuit projects also would provide redistribution of loads on circuits served from Boat substation and Macaw substations, respectively.

In terms of identified post-contingency load shift enhancement needs, the Optimal DER Portfolio projects enhance post-contingency load shift opportunities in a number of circuits. The projects on the 24 circuits listed above would provide enhanced load shift opportunities addressing identified needs in the following systems:

- Shellfish
- Tree
- Modjazz
- Sail
- Wildcat
- Music

3.3.2. Reliability

In this project's reliability assessment approach the researchers evaluated the specific impact of particular network enhancement measures on reliability through three mechanisms – reductions in load that expand post-contingency load shift opportunities, reductions in load that permit substations with constrained ex-substation ties to operate through loss-of-bank contingencies, and load reductions reducing otherwise elevated line failure risk. For a given system measure to improve reliability by expanding post-contingency load shift opportunities, the researchers viewed that two conditions must be met. First, the measure must provide enough load relief to move a circuit from "ineligible" to "eligible" to accept load shifts. Second, that circuit (the relieved circuit) must serve as a backup to another circuit having otherwise compromised load shift opportunities – that is, the incremental load shift opportunity must be consequential in terms of reliability. This type of analysis, incorporating such circuit-to-circuit interactions, is only possible using a systemwide model that captures all of the tie and alternate source possibilities of each circuit.

Of the expanded set of network measures, only measures that reduce or redistribute load can affect reliability as the researchers define it in this rubric. Therefore, there is potential reliability value associated with DER projects providing incremental capacity, such as demand response, distributed generation, and storage. There is also potential reliability value under this project's rubric associated with substation expansion projects and circuit expansion projects. There is also conceivably reliability value associated with alternate topologies as they redistribute load; however, the researchers evaluated alternate topologies only for their voltage and loss impacts.

Again, the researchers treated the relief of actual overloads as a separate benefit, "Load Relief," discussed in Section 3.3.11.

As stated in Section 3.2.6, the researchers found that 2005 Optimal DER Portfolio distributed generation projects on two circuits represented sufficient capacity to open those circuits to post-contingency load transfers and, in doing so, enhance post-contingency load transfer opportunities of sibling circuits otherwise having compromised load transfer options. In each case, these reliability impacts (reductions in expected unserved energy) occur under normal summer peak conditions. The researchers found that 2005 Optimal DER Portfolio demand response projects on four circuits represented sufficient capacity to open those circuits to post-contingency load transfers, and, in doing so, it enhances post-contingency load transfer opportunities of sibling circuits otherwise having compromised load transfer options. In each case, the impacts would occur only under super-peak conditions. Because these conditions represent such a small share of the operating year, the overall impact on reliability in annual terms is much smaller.

Of the circuits with line segments sufficiently loaded under one or more of the 2005 operating conditions to elevate their posited failure rate, only Peach had enough demand response capacity among the 2005 Optimal DER Portfolio projects to eliminate the condition, and only under super-peak conditions. Again, because this benefit occurs under a small share of the operating year, the measured overall impact on reliability in annual terms is small.

The results of the evaluation of the 2005 Optimal DER Portfolio projects on Hobby system reliability are restated from Section 3.2.6 in Table 36 and Table 37, with the addition of the utility/ratepayer benefit posited by NCI.

Table 36. Load shift benefits of 2005 Optimal DER Portfolio projects

Projects	Affected Circuit(s)	Outage Impact (h/yr)	Unserved Energy Impact (kWh/yr)	Impact in Customer VOS ($/yr)	Impact in Utility/Ratepayer VOS ($/yr)
Blanket Ckt DG Projects	Ketch	.72	7,027	$52,927	$35,135
Net Ckt DG Projects	Towel	1.10	10,185	$37,515	$50,925
Spur Ckt DR Projects	Bit	.01	128	$513	$640
Chromium Ckt DR Projects	Copper	-	41	$372	$205
Apple Ckt DR Projects	Peach, Pear	.07	636	$2,362	$3,180
Lynx Ckt DR Projects	Tiger, Wildcat	.03	307	$3,167	$1,535

Table 37. Overload reduction benefits of 2005 Optimal DER Portfolio projects

Circuit DR Projects	Outage Impact (h/yr)	Unserved Energy Impact (kWh/yr)	Impact in Customer VOS ($/yr)	Impact in Utility/Ratepayer VOS ($/yr)
Peach Ckt DR Projects	-	66	$200	$330

In aggregate, the impact of these DER projects totals 18,390 kWh/yr in avoided unserved energy. By way of comparison, in its evaluation of the 2005 Optimal DER Portfolio projects, NCI estimated a reduction in annual sustained outages of 11,909 hours per year, or 21,883 kWh/yr due to both a reduction in elevated trip risk due to circuit loading and enhanced post-contingency load shift opportunities for the entire Hobby system.

As stated earlier, the key differences in the two approaches are that the researchers' reliability assessment evaluates individual line segments for their loading relative to their rating, individual circuits for their post-contingency load transfer opportunities, and individual substations for their ability to either operate through transformer bank outages or lay off load via circuit-level load shifts. This project's approach also incorporates the total reliability risk on circuits served from parent circuits. This level of granularity is consequential – the results Section 3.2.2 show very dramatically that the cumulative effect of these factors results in vastly different reliability risk from circuit to circuit. The researchers also priced reliability improvements based on the actual customer class makeup of each affected circuits.

The overall findings of the reliability impact (change in expected unserved energy) of the 2005 Optimal DER Portfolio projects with the two approaches are quite similar on a system level. However, through explicit evaluation of circuit-to-circuit reliability risk differences, the researchers find the specific DER projects yielding reliability benefits and the reach of those benefits will be somewhat more limited—to a few projects and a few circuits. In addition, the researchers found that overload relief *per se* is a small contributor to the overall reliability benefit, where expansion in post-contingency load shift opportunities is a more important contributor to reliability improvement.

The 3,000 2011 Optimal DER Portfolio demand response projects and 3,000 2011 Optimal DER Portfolio distributed generation projects the researchers identified Section 3.2.6 lack sufficient capacity within any one substation to permit that substation to operate through a loss-of-largest bank contingency. However, in Section 4.2, Commercialization Potential, the researchers identified 2011 Optimal DER Portfolio projects on 25 circuits that have a meaningful impact on reliability. In every case but one, the reliability benefit arises entirely from the expansion of post-contingency load shift opportunities. The one exception is Mussel circuit, which has sufficient DER capacity within the Optimal DER Portfolio to overcome a 120% of normal overload condition, resulting in a reduced failure rate under the researchers' assumptions. That impact alone represents 497 kWh/yr of the 16,679 kWh/yr reliability impact for Mussel Circuit DER.

The reliability impacts of these 25 circuits' 2011 Optimal Portfolio DER projects are shown in Table 38. These values are not additive, as the circuits that benefit from the enhanced load shift opportunities provided by different circuits' DER projects are in some cases the same. However, this table does show that the DER projects on some circuits such as those on Smock, Watercolor, and Saddle circuits have significantly higher reliability value relative to the group.

Table 38. Optimal DER Portfolio Projects reliability benefits

Project	Un-served Energy Impact (kWh/yr)	Impact in Customer VOS ($/yr)	Impact in Utility/Ratepayer VOS ($/yr)
Sloop Ckt DER Projects	33,609	$374,298	$168,045
Yawl Ckt DER Projects	48,202	$312,869	$241,010
Wrasse Ckt DER Projects	46,364	$351,317	$231,820
Barbera Ckt DER Projects	8,781	$80,579	$43,905
Muscat Ckt DER Projects	23,259	$192,186	$116,295
Riesling Ckt DER Projects	39,258	$257,261	$196,290
Roan Ckt DER Projects	31,586	$181,103	$157,930

Project	Un-served Energy Impact (kWh/yr)	Impact in Customer VOS ($/yr)	Impact in Utility/Ratepayer VOS ($/yr)
Rich Ckt DER Projects	10,332	$38,431	$51,660
Cadmium Ckt DER Projects	20,128	$139,321	$100,640
Chromium Ckt DER Projects	32,008	$288,469	$160,040
Brecker Ckt DER Projects	30,784	$345,037	$153,920
Carter Ckt DER Projects	20,496	$63,066	$102,480
Flute Ckt DER Projects	7,398	$65,025	$36,990
Guitar Ckt DER Projects	20,234	$141,667	$101,170
Trombone Ckt DER Projects	26,587	$154,625	$132,935
Smock Ckt DER Projects	57,654	$599,087	$288,270
Watercolor Ckt DER Projects	51,531	$464,307	$257,655
Exclusion Ckt DER Projects	16,411	$76,686	$82,055
Bridle Ckt DER Projects	7,318	$78,762	$36,590
Saddle Ckt DER Projects	51,603	$255,148	$258,015
Spur Ckt DER Projects	46,869	$260,203	$234,345
Dinghy Ckt DER Projects	36,026	$232,629	$180,130
Mussel Ckt DER Projects	16,679	$141,155	$83,395
Cedar Ckt DER Projects	28,961	$217,908	$144,805
Panther Ckt DER Projects	15,324	$62,834	$76,620

These results also suggest that under this project's reliability rubric, at least for this system, expanding post-contingency load shift opportunities using circuit-level DER is a far more potent reliability measure than expanding the substation reserve transformer capacity or relieving overloads on individual circuits.

This is a reasonable conclusion. First, the researchers' circuit-level approach reveals the measures that enhance post-contingency load shift opportunities for individual circuits whose reliability risk is elevated due to the lack of such opportunities, so the DER projects identified in Table 38 are the ones that show very high impacts because they affect multiple, high-value circuits, and thus remain after multiple screens. Second, under a loss-of-bank contingency, all the ties of all of the circuits served from the substation are nominally available to implement any necessary load shifts. The researchers' approach attributes a reliability benefit to reserve transformer bank capacity only to the extent there is incremental avoided unserved energy due to eliminating the need to make any load shifts. Third, the elevated failure risk the researchers assume for a loaded circuit affects only that circuit and is mitigated by that circuit's load shift opportunities. The researchers' approach attributes a reliability benefit only to the extent that there is incremental avoided unserved energy due to eliminating that elevated failure risk.

Of Hobby system's proposed network expansion projects the researchers evaluated using the 2011 Hobby simulation, the Macaw, Cloud, Oyster, and Weckl substation projects would enable individual substations to continue serving their loads within emergency limits under a loss-of-largest bank contingency. Of these, the Oyster project affects two substations, Oyster and Shellfish, which have sufficient external ties to shift load under such a contingency, so there is no reliability "benefit" for the Oyster substation project. From a separate evaluation of the transformer bank projects, which the researchers did not actually simulate, among the Music, Heron, Paint, and Ride transformer bank projects, only Ride provides enough incremental capacity to allow the substation to serve its 2011 loads under a loss-of-largest-bank contingency.

Table 39 shows the reliability impact of these projects in terms of avoided unserved energy and in customer-value-of-service terms.

Table 39. Utility network expansion projects reliability benefits

Project	Substation Emergency Loading Relief	Unserved Energy Impact (kWh/yr)	Impact in Customer VOS ($/yr)	Impact in Utility/Ratepayer VOS ($/yr)
Caraval Ckt				
Starling Ckt				
Container Sub				
Fastener Sub				
Macaw Sub	Macaw	23,499	$146,087	$117,495
Cloud Sub	Cloud (Preventer)	4,139	$39,667	$20,695
Oyster Sub	Oyster, Shellfish			
Weckl Sub	Weckl, Modjazz	1,402	$28,383	$7,010
Ride Xfr	Ride	2,044	$9,214	$10,220

3.3.3. Power Quality

As stated earlier, under NCI's definition of power quality as a benefit category, sagging voltage at a customer site could increase the share of minor but common PQ events posited in the NYSERDA PQ event distribution that result in delivered voltages outside the ITI voltage tolerance envelope, causing interrupted customer processes or equipment damage. DER (or any network performance enhancement measure) that reduces voltage sag (i.e., increases peak-period voltage) or simply brings customer delivery voltages closer to nominal in general would provide a power quality benefit.

The researchers mapped the NYSERDA distribution of PQ events and the ITI voltage impact envelope provided by NCI and found that within an average customer delivery voltage range of 0.94 PU to 1.0 PU a 0.01 PU increase in delivery voltage might reduce by 10% the share of PQ events of 0.5 seconds or more with sufficient voltage deviation from nominal to cause a customer process interruption. This appears consistent with NCI's mapping of these data.

There are several voltage-oriented network performance enhancement measures that appear to have the potential to improve customer delivery voltages in lower-voltage areas by 10% (0.01 PU) or more, thus a 10% reduction in PQ events causing process interruptions is realistic. Given NCI's estimate of $20 million annually in customer costs associated with PQ-related events for the Hobby system, this translates to a potential annual power quality benefit value to customers of $2 million. This conclusion is also consistent with NCI's findings.

In this study, the researchers evaluate essentially every network performance enhancement measure in terms of voltage impacts. The researchers have shown that a variety of network performance enhancement measures can affect system voltage, and that these impacts can in some cases be attributed to small groups of highly impactful measures. In most cases, the researchers discuss voltage improvements in terms of an improvement in the systemwide minimum voltage primarily because this measure is sufficiently sensitive to reveal differences among projects. In some cases, the researchers also discuss voltage improvement in terms of an increase in the systemwide average voltage, a decrease in the voltage variability within the system, or a reduction in the number of low-voltage buses. As indicated by Figure 22 and Figure 23 below, these are all indicators of flatter voltage profiles and mitigation of low voltage conditions, both of which would yield improvements in power quality under NCI's definition.

Voltage improvements affecting power quality could come on a sustained basis, or they could come from demand response if these resources are called in response to voltage events and/or can respond quickly enough to mitigate voltage deviations.

The recontrol results discussed in Section 3.2.3 show that ideal settings of existing controls could have a significant impact on voltage. These results are restated in Table 40 below, in terms of the impact on the overall systemwide minimum voltage. These results reflect a systemwide optimization using GRIDfast™ of transformer taps, capacitor dispatch, and the VAR output of existing embedded generation with the objective of simultaneous minimization of real losses, reactive losses, and voltage deviation from nominal. The change is relative to the system with the configuration of those elements taken from system data. As indicated in Section 3.2.3, for comparison purposes in the absence of field data for an unoptimized system, the researchers have extended the voltage benefit from recontrols found in the September 2009 case to the 2011 forecast case.

Table 40. Voltage impacts of recontrols

Hobby System	Operating Conditions	V min Improvement (PU)
November 2005	Summer Peak	0.047
"	Winter Peak	0.046
"	Super-peak	0.036
"	Off Peak	-0.007
"	Minimum Load	0.006
September 2009	Summer Peak	0.026
2011 Forecast	Summer Peak	0.026

Table 40 shows that under summer peak load conditions ideal control settings can increase voltage in the lowest-voltage locations (or reduce "sag") by well over 0.01 PU. It is reasonable to project, therefore, that ideal control settings can improve voltage in additional – and perhaps most – low-voltage areas under peak load conditions by 0.01 PU or more, improving power quality.

In Section 3.2.4, the researchers showed that there are potential voltage benefits from coordinated dispatch of certain of the existing demand response projects in the Hobby system. The researchers assumed existing demand response, as an energy-limited resource, was only available for dispatch under super-peak conditions. From among the over 4,600 existing demand response projects in the Hobby system, the researchers identified 125 demand response resources on 11 circuits that if dispatched as a group would yield disproportionate network performance benefits, specifically voltage benefits, under super-peak conditions. The researchers also identified a second tier of 875 existing demand response resources that would measurably improve system voltage if dispatched as a group. The voltage impacts of the remaining nominally beneficial existing demand response projects were found to be modest. These results are summarized in Table 41.

Table 41. Voltage impacts of existing demand response

Hobby System	Operating Conditions		Vmin Improvement (PU)
November 2005	Super-peak	125 top-ranked DR	0.004
"	"	825 next-ranked DR	0.007

Table 41 suggests that coordinated dispatch of existing demand response resources could improve voltage in low-voltage areas under peak load conditions, though by far less than ideal control settings and provided the number of resources under control is large enough.

In Section 3.2.5, the researchers demonstrated that there could be significant voltage benefits from alternative topologies. The researchers identified "networking portfolios" of specific switch closures for a lightly networked system that will yield most of the theoretical voltage benefit from fully networked topology for the 2005 system and the 2011 system.

As noted in Section 3.2.3, the systemwide low-voltage conditions in the 2011 forecast case are largely corrected through recontrols, and the "networking portfolio" comprised of the top 14-ranked networking switch closures has a modest impact on the systemwide minimum voltage itself. However, as shown in Figure 22 and Figure 23 repeated from Section 3.2.5, even with little change in the systemwide minimum voltage, these networking switch closures yield voltage benefits in terms of reduced voltage variability. This illustrates the general point that an improvement in the systemwide minimum voltage is but one indicator of good things happening in the system from these measures that can improve power quality, as defined by NCI. The impacts of each networking portfolio on systemwide minimum voltage are shown in Table 42.

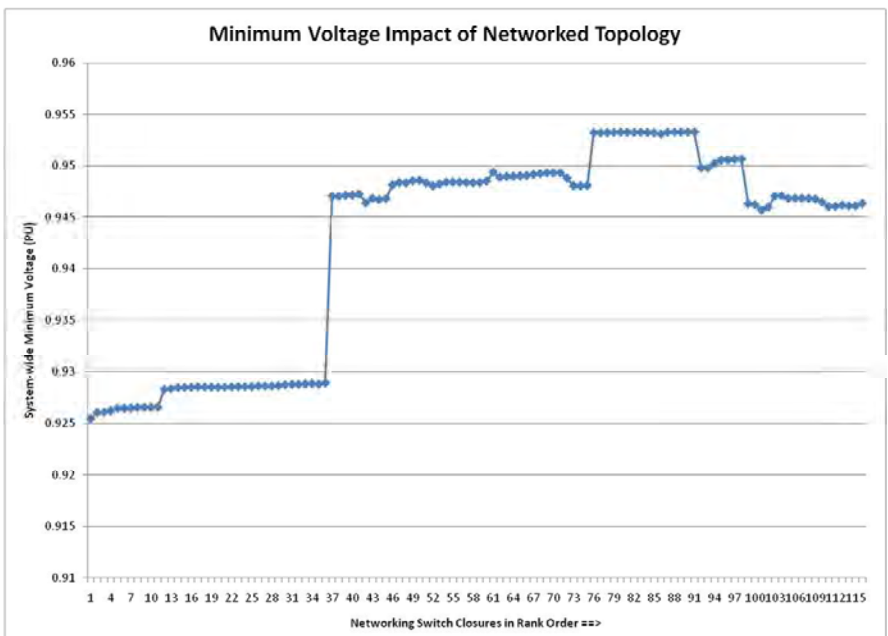

Figure 22. Minimum voltage impact of networked topology

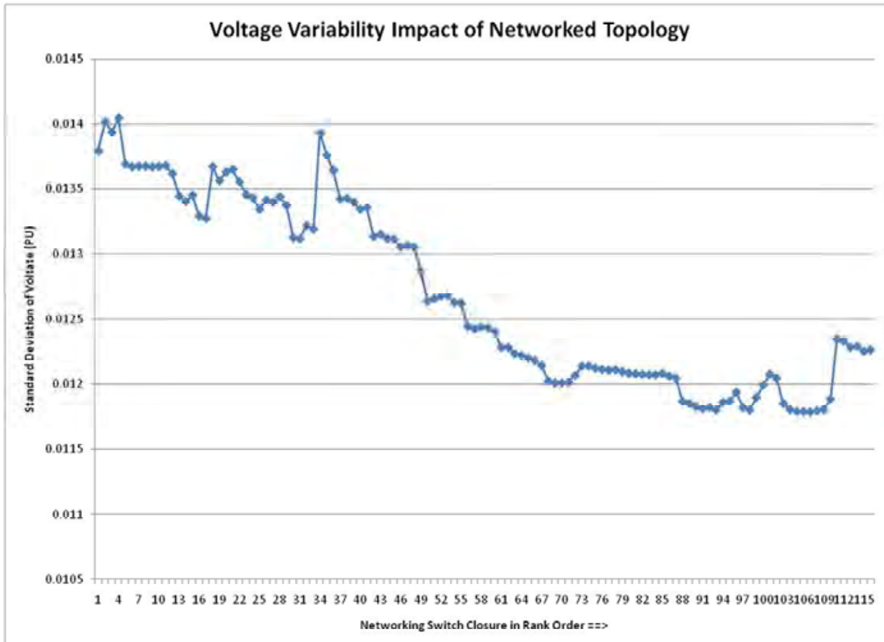

Figure 23. Voltage variability impact of networked topology

Table 42. Voltage impacts of "Networking Portfolios" of switch closures

Hobby System	Operating Conditions	Vmin Improvement (PU)
November 2005	Summer Peak	0.045
"	Winter Peak	0.011
"	Super-peak	0.047
2011 Forecast	Summer Peak	-

Table 42 suggests that the 2005 "networking portfolio" could improve voltage in low-voltage areas under peak load conditions by 0.01 PU or more, providing a power quality benefit.

In Section 3.2.6, the researchers developed Optimal DER Portfolios of distributed resources additions selected specifically for their impact on losses and voltage.

Of the capacitors, demand response, distributed generation, and storage projects in the 2005 Optimal DER Portfolio, the researchers identified a subset of "voltage benefit" projects that have disproportionate impacts on voltage under one or more operating conditions.

The 2005 Optimal DER Portfolio consists of 157 capacitor additions, 22 of which, representing 6.15 MVAR, are "voltage benefit" additions having disproportionate voltage impacts under one or more operating conditions. The seasonal impacts on systemwide minimum voltage of these 22 capacitor additions are summarized in Table 43.

Table 43. Voltage impacts of Optimal DER Portfolio "Voltage Benefit" capacitor additions

Hobby System	Operating Conditions	V min Improvement (PU)
November 2005	Summer Peak	0.080
"	Winter Peak	-
"	Super-peak	0.062
"	Off-peak Hour	0.010
"	Minimum Load	0.0047

The 2005 Optimal DER Portfolio includes 22,147 demand response additions, of which 4,192 are "voltage benefit" projects that have disproportionate voltage impacts under summer peak, super-peak, and/or off-peak conditions. The seasonal impacts of these "voltage benefit" projects are summarized in Table 44.

Table 44. Voltage impacts of 4,192 Optimal DER Portfolio demand response additions

Hobby System	Operating Conditions	Vmin Improvement (PU)
November, 2005	Summer Peak	0.001
"	Super-peak	0.014
"	Off-peak Hour	0.0005

The 2005 Optimal DER Portfolio includes 1,396 distributed generation additions that have disproportionate voltage benefits under one or more sets of operating conditions. The seasonal impacts of these projects on the systemwide minimum voltage are summarized in Table 45.

Table 45: Voltage impacts of 1,396 Optimal DER Portfolio DG projects

Hobby System	Operating Conditions	Vmin Improvement (PU)
November 2005	Summer Peak	0.036
"	Winter Peak	0.011
"	Super-peak	-
"	Off-peak Hour	0.0048

The 2005 Optimal DER Portfolio includes 1,488 individual storage projects ranging from 10 kW to 60 kW in size at each site. As a group, these projects increase the systemwide minimum voltage under super-peak conditions by 0.0002 PU.

The 2011 Optimal DER Portfolio consists of capacitor, demand response, and distributed generation, all of which are high voltage value projects. Their impact on systemwide minimum voltage for 2011 forecast summer peak conditions is summarized in Table 46.

Table 46. Voltage impacts of 2011 Optimal DER portfolio additions

Hobby System	Type	Operating Conditions	Vmin Improvement (PU)
2011 Forecast	3 Capacitor Additions	Summer Peak	0.0096
"	3,000 DR Projects	"	0.0129
"	3,000 DG Projects	"	0.022

Table 44 and Table 45 suggest that of the 2005 Optimal DER Portfolio resource additions, the capacitors and distributed generation clearly have the potential to improve voltage in low-voltage areas under peak load conditions by 0.01 PU or more, providing a power quality benefit. At least the 2005 group of distributed storage projects would not have a meaningful voltage-related power quality impact. Again, this is likely due to the researchers' ordering of these resource additions.

Table 46 suggests that of the 2011 Optimal DER Portfolio resource additions, the distributed generation has the greatest potential to improve voltage in low-voltage areas under peak load conditions by 0.01 PU or more, providing a power quality benefit.

The results of Section 3.2.8 show that clearly some of the network expansion projects from the Hobby system capital plan have meaningful voltage impacts. These results are restated in Table 47.

Table 47. Voltage impacts of network expansion projects

Hobby System	Operating Conditions	Project	Vmin Improvement (PU)
2011 Forecast	Summer Peak	Caraval Ckt	0.00
"	"	Starling Ckt	0.0001
"	"	Container Sub	-0.0001
"	"	Fastener Sub	-0.0001
"	"	Macaw Sub	0.0047
"	"	Cloud Sub	0.0016
"	"	Oyster Sub	-0.0007
"	"	Weckl Sub	0.0042

Table 47 suggests that of the network expansion projects, only the Macaw and Weckl substation projects have voltage impacts in low-voltage areas approaching a level to provide a power quality benefit.

These results suggest that of this expanded set of network measures, recontrols have a very significant potential impact on voltage sag (i.e., voltage impact in low-voltage areas under peak conditions) and thus could have a power quality benefit. Lightly networked topology can also have significant voltage impacts, depending on operating conditions. Capacitor additions in the right locations can also have significant voltage impacts, but again this depends on operating conditions. Clearly some specific distributed generation projects can have voltage impacts under some conditions. All of these measures other than the network expansion projects were identified specifically for their voltage impacts (and loss impacts). This explains why by comparison even the more impactful network expansion projects have relatively little voltage impact.

As described above, NCI posited a 1% reduction in power quality-related costs to customers arising from a 0.01 PU improvement in voltage sag in low-voltage locations, for an aggregate area wide economic benefit of $2 million annually, and the researchers' evaluation of the NYSERTA and ITI data from NCI supports the reasonableness of this outcome. The researchers' evaluation of these network performance enhancement measures suggests that a 1% improvement in average voltage in low-voltage areas and the related power quality benefit are achievable, and in the absence of a more refined analysis, the researchers can allocate this total benefit to the most high-impact resources. Table 48 shows the area wide power quality benefit allocated to different network measures based on their Vmin impact.

Table 48. Power quality impacts

Hobby System	Project	Nominal Capacity (MW)	Power Quality Value ($/yr)
2005	Recontrols	-	$434,783
"	Coordinated Dispatch, Top 1,000 Existing DR	3.30	$64,755
"	Networking Portfolio	-	$416,281
"	22 Capacitor Additions	-	$740,056
"	4,192 DR Projects	33.751	$9,251
"	1,396 DG Projects	35.206	$333,025
"	1,488 Storage Projects	35	$1,850
2011 Forecast	Recontrols	-	$654,912
"	Networking Portfolio	-	-
"	3 Capacitor Additions	-	$241,814
"	3,000 DR Projects	14.93	$324,937
"	3,000 DG Projects	46.86	$554,156
"	Caraval Ckt	-	-
"	Starling Ckt	-	-
"	Container Sub	-	-
"	Fastener Sub	-	-
"	Macaw Sub	-	$118,388
"	Cloud Sub	-	-
"	Oyster Sub	-	-
"	Weckl Sub	-	$105,793

The NYSERDA PQ event distribution and the ITI PQ event threshold curve identified by NCI offer the possibility of a much more refined approach to power quality impacts that could be explored. It should be possible using the Energynet® model to assess average delivered voltage and voltage "sag" under peak conditions at each individual location serving a commercial or industrial load. The voltage impact on this population of locations of any given network performance improvement measure could be directly evaluated through simulations; moreover, measures could conceivably be developed specifically for their ability to address voltage deviations at these locations.

3.3.4. Conservation Voltage Reduction

As stated, voltage improvement was a primary consideration in the identification and evaluation of nearly every network performance enhancement measure evaluated in this project. In the discussion under power quality above, the researchers summarize the project findings of the voltage impacts of a variety of network performance enhancement measures, including recontrols, coordinated dispatch of certain existing demand response, the "networking portfolios," Optimal DER Portfolio capacitor additions, demand response, distributed generation, and storage, and the network expansion projects from the Hobby system capital plan.

The voltage impacts of these projects are stated in terms of the impact on the overall systemwide minimum voltage, but those results show that there are also impacts in terms of reduced voltage variability and increased overall voltage. Nonetheless, none of the simulations performed for this project was set up in anticipation of conservation voltage reduction as a specific voltage-related benefit category. Thus for purposes of this project, the researchers adopted the NCI approach, concluding that a given level of conservation voltage reduction (CVR) is possible on certain circuits based on their customer makeup.

Of the network performance enhancement measures having voltage benefits identified in the discussion on power quality, arguably only recontrols, networked topology, capacitor and distributed generation additions, and the network expansion projects from the Hobby system capital plan contribute to CVR benefits. Implementation of CVR would require sustained voltage improvements that would not be provided by demand response or storage.

Further, contribution to CVR and power quality are clearly different and arguably additive benefits for network performance enhancement measures that support both. However, there is also tension between the two benefits; where power quality is improved with higher average delivery voltage to the customer (keeping a greater share of minor voltage deviation events within equipment tolerance bands), CVR relies on reduced average delivery voltage. In the researchers' view, both power quality and CVR as defined here are enabled through the remediation of low-voltage buses and flatter voltage profiles.

Accordingly, for purposes of this analysis, the researchers first determine the overall potential CVR benefit, and then attribute that benefit to measures shown to improve voltage by allocation.

In the 2011 Hobby system simulation, the researchers identified 12 circuits eligible for CVR, based on their customer makeup. By excluding all circuits with any industrial or medium to large business loads, the remaining circuits happen to be quite lightly loaded, averaging only 580 kW. If the aggregate forecast summer peak load on these circuits is reduced by 1% through reduced voltage, it results in a demand reduction of 70 kW, and if that reduction prevails over summer and winter peak periods of the year, it yields an annual energy savings of 347,700 kWh and an annual benefit of $34,074 if valued at $0.098/kWh.

In its evaluation of the 2005 Optimal DER Portfolio projects, NCI determined that distributed generation additions would stabilize circuit voltages to permit CVR on 26 circuits, and 28 circuits in its "high penetration" scenario. NCI assumed that on those circuits a feeder-level voltage benefit of 1.0% under summer peak conditions and 0.25% under winter peak conditions could be applied to conservation voltage reduction. These voltage reductions would in turn result in proportional reductions in energy consumption during the periods when CVR was implemented, and NCI assumed a 53% load factor for CVR. NCI priced the reduced consumption using seasonal energy values and determined an annual CVR benefit of $188,000 for the entire Hobby system. This is not wholly inconsistent with the researchers' results for the 2011 system as it includes off-peak benefits and double the number of "eligible" circuits. These results, allocated to individual sets of projects based on their Vmin impact, are presented in Table 49.

Table 49. CVR impacts

Hobby System	Project	Nominal Capacity (MW)	CVR Value ($/yr)
2005	Recontrols	-	$42,540
"	Coordinated Dispatch, Top 1,000 Existing DR	3.30	-
"	Networking Portfolio	-	$40,696
"	22 Capacitor Additions	-	$72,348
"	4,192 DR Projects	33.751	-
"	1,396 DG Projects	35.206	$32,557
"	1,488 Storage Projects	35	-
2011 Forecast	Recontrols	-	$13,278
"	Networking Portfolio	-	-
"	3 Capacitor Additions	-	$4,903
"	3,000 DR Projects	14.93	-
"	3,000 DG Projects	46.86	$11,235
"	Caraval Ckt	-	-
"	Starling Ckt	-	-
"	Container Sub	-	-
"	Fastener Sub	-	-
"	Macaw Sub	-	$2,400
"	Cloud Sub	-	-
"	Oyster Sub	-	-
"	Weckl Sub	-	$2,145

NCI noted that there are unpriced secondary benefits to this reduced load, such as reduced reserve margin requirements and reduced losses. This energy consumption reduction would also result in benefits of reduced emissions.

CVR could be implemented by substation where the served circuits all have sufficiently flat voltage profiles such that delivery voltages can be maintained within the desired range even with lower overall voltages. The following illustrates such an analysis.

The Hobby Energynet® simulation has field voltage reads mapped by circuit and simulated results voltage values for all points in between. Table 50 shows the high and low voltage from the simulation for all the buses of each circuit served from one substation, in this case Ride substation. It also shows the high and low voltage from field voltage monitoring sites where available. Ride was selected through an assessment of all of the voltage profiles of all of the Hobby circuits performed using the Energynet® model.

Table 50. Ride substation circuit voltage profiles

		Field Voltage Monitoring Sites			Simulation - All Buses		
Circuit_Name	**Substation_Name**	**max**	**min**	**diff**	**max**	**min**	**diff**
Hay	Ride 115/12 (D)	#N/A	#N/A	#N/A	1.026	1.025	0.002
Horseshoe	Ride 115/12 (D)	#N/A	#N/A	#N/A	1.026	1.026	0.000
Girth	Ride 115/12 (D)	1.018	1.005	0.012	1.026	0.996	0.029
Halter	Ride 115/12 (D)	1.035	0.978	0.057	1.026	1.000	0.026
Saddle	Ride 115/12 (D)	1.000	0.968	0.032	1.026	0.980	0.046
Spur	Ride 115/12 (D)	1.020	0.976	0.044	1.020	0.993	0.026
Bit	Ride 115/12 (D)	1.018	1.002	0.017	1.020	1.000	0.020
Bridle	Ride 115/12 (D)	1.023	1.001	0.022	1.020	0.993	0.027
Blanket	Ride 115/12 (D)	1.013	1.002	0.011	1.020	0.994	0.025
Brush	Ride 115/12 (D)	1.028	1.013	0.016	1.020	1.000	0.020
	Ride 115/12 (D) Average						0.022

Apart from Saddle circuit, among this substation's circuits the difference between the high voltage and the low voltage in each circuit is consistently low in the simulation. The low voltages are also relatively high, again, other than on Saddle circuit. The low field voltage on Saddle is not reflected in the simulation; this may be a capacitor modeled as "on" in the simulation but not operating properly in the field. Subject to some further investigation, this substation and its circuits may be a candidate for voltage reduction of 2% of nominal or more.

In the 2011-forecast case the total load served from the Ride substation is about 78 MW. A 2% reduction in voltage at every point on circuits served from that substation would reduce power

(MW) consumption according to the makeup of the loads. If the researchers assume a percentage-for-percentage reduction in power for reduction in voltage, the reduction in power would be about 1.56 MW.

This analysis suggests that the energy consumption reduction potential from CVR is *much* higher than what is suggested from either NCI's results or the researchers results using their circuit customer makeup-based methodology. While this analysis does not directly address the point, it is possible to infer that measures that correct local low voltage and permit CVR on a greater number of circuits may be the most impactful voltage management measure.

3.3.5. Bulk System Capacity

From Section 3.2.6, the Optimal DER Portfolio for the 2005 Hobby system includes 22,147 demand response additions representing a total available capacity of 8.5 MW, and 128.7 MW under super-peak conditions. The researchers also presented a more rarified portfolio of the 4,192 highest-value demand response additions representing a total available capacity of 4.9 MW, and 31.8 MW under super-peak conditions. The latter set of projects was selected for both their loss impact and their voltage impact. For these projects the researchers restricted operation of the large number of residential and small business HVAC cycling projects to super-peak conditions, hence the difference in the available capacity.

The Optimal DER Portfolio for the 2005 Hobby system also includes 1,396 distributed generation additions representing a total capacity of 35.206 MW. Each of these projects has a characteristic size and annual operating profile.

The Optimal DER Portfolio for the 2005 Hobby system also includes 1,488 distributed storage projects representing approximately 35 MW of on-peak capacity. Each of these has a characteristic size.

In Section 3.2.6, the researchers identified 3,000 Optimal DER Portfolio demand response and distributed generation additions for the 2011 Hobby system using the same approach; these represent 14.93 MW and 46.86 MW, respectively. Because this portfolio was also selected based on both loss and voltage impacts, it is most analogous to the smaller demand response portfolio from the 2005 studies. However, as this study is based on a single operating condition (summer peak), the researchers did not directly specify seasonal availability or dispatch. To provide a basis for comparison of energy, loss, capacity, and emission impacts of the 2011 Hobby system demand response resources, the researchers assumed the entire portfolio of demand response resources was available at any time, but with limits on annual dispatch.

To provide a basis for comparison of energy, loss, capacity, and emission impacts, the researchers assumed all the dispatchable generation projects within each type and customer class had the same operating and availability profile as the 2005 Optimal DER Portfolio distributed generation projects in aggregate within that same type and customer class.

Using the capacity values from Section 2.3.4 for the Optimal DER Portfolio projects, the researchers found the following in terms of bulk system capacity in Table 51.

Table 51. Bulk system capacity value of Optimal DER Portfolio additions

Hobby System	Type	Capacity	Bulk System Capacity Annual Value
November 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$2,164,819
"	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$7,939,628
"	1,396 DG Projects	26.2 MW	$3,311,988
"	1,488 Storage Projects	35 MW	$3,655,697
2011 Forecast	3,000 DR Projects	14.93 MW	$1,120,335
"	3,000 DG Projects	46.86 MW	$3,198,992

As expected, nearly all of the total bulk system capacity value of these resources is attributable to their peak-period capacity. Demand response is evidently a particularly potent capacity resource if large penetrations are possible.

3.3.6. Ancillary Services Capacity

The researchers did not ascribe an additional value opportunity beyond bulk system capacity for DER capacity during summer peak periods, because the bulk system capacity values the researchers used from Section 2.3.4 are actually higher than the assumed values for any ancillary services category in Section 2.3.5. Accordingly, the great majority of the nominally beneficial demand response projects identified in Section 3.2.6, which are summer-peak-only residential and small commercial HVAC cycling, are excluded from this opportunity.

Under 2005 winter peak and off-peak conditions, the total volume of beneficial demand response capacity that the researchers identified is less than the Hobby system's spinning reserve needs of 13.5 MW and 6.7 to 9.8 MW, respectively. The researchers also assume based on the CERTS findings that the dispatch limits for demand response do not apply to the provision of spinning reserves with short-duration dispatch. Therefore, the researchers assume all of the 2005 portfolio demand response capacity available under winter peak and off-peak conditions will be used for spinning reserves. For the 2011 demand response additions, the researchers assume half the winter peak and off-peak capacity will be used for spinning reserves.

The total volume of storage capacity that the researchers identified exceeds the Hobby system's needs for regulation reserve capacity under winter peak conditions; therefore, the researchers assume that only a share of the storage projects will be used for regulation reserves, with the remainder receiving credit for bulk system reserves instead.

For the Optimal DER Portfolio projects, the following in terms of ancillary reserves capacity value is shown in Table 52.

Table 52. Ancillary services value of Optimal DER Portfolio projects

Hobby System	Type	Nominal Capacity	Ancillary Services Capacity Annual Value
November 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$381,330
"	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$714,132
"	1,488 Storage Projects	35 MW	$270,000
2011 Forecast	3,000 DR Projects	14.93 MW	$671,962

In the case of both demand response and storage, relatively low-value bulk system capacity in off-peak and/or off winter periods is substituted for somewhat more valuable regulation reserves for storage and spinning reserves for demand response. Table 53 below shows the restated bulk system capacity values after allowing for the use of storage and demand response capacity for ancillary services as described.

Table 53. Restated bulk system capacity value of Optimal DER Portfolio projects

Hobby System	Type	Capacity	Bulk System Capacity Annual Value
November, 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$2,085,673
"	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$7,792,560
"	1,396 DG Projects	26.2 MW	$3,311,988
"	1,488 Storage Projects	35 MW	$3,573,603
2011 Forecast	3,000 DR Projects	14.93 MW	$984,148
"	3,000 DG Projects	46.86 MW	$3,198,992

3.3.7. System Voltage Security

In the set of 22,147 nominally beneficial demand response additions identified for the 2005 Hobby system in Section 3.2.6, there are 18,842 residential and small businesses HVAC cycling projects representing a total of over 111 MW of super-peak capacity. Under the parameters set by NCI, this is more than enough capacity to provide a system voltage security benefit. Further, this benefit is additive to the other capacity and ancillary services benefits attributable to these demand response projects.

Note in Section 3.2.6 the researchers identified for the 2011 Optimal DER portfolio 3,000 demand response projects. These projects as groups represent less than 15 MW of capacity, and the HVAC cycling share is even less. Thus, this portfolio of demand response is not large enough to provide a system voltage security benefit.

Accordingly, based on the NCI results in Section 2.3.6, the researchers attribute a $90,000 annual system voltage security benefit only to the residential and small business HVAC cycling demand response projects among the larger set of 2005 Optimal DER Portfolio demand response additions.

3.3.8. Energy

The Optimal DER Portfolio for the 2005 Hobby system includes 22,147 demand response additions representing a total capacity of 8.5 MW, and 128.7 MW under super-peak conditions. The researchers also presented a more rarified portfolio of the 4,192 highest-value demand response additions representing a total capacity of 4.9 MW, and 31.8 MW under super-peak conditions. The latter set of projects was selected for both their loss impact and their voltage impact. For these projects, the researchers restricted operation of the large number of residential and small business HVAC cycling projects to super-peak conditions, hence the difference in the available capacity.

In Section 3.2.6, the researchers identified 3,000 Optimal DER Portfolio demand response additions for the 2011 Hobby system using the same approach; these represent 14.93 MW. Because this portfolio was also selected based on both loss and voltage impacts, it is most analogous to the smaller portfolio from the 2005 studies. However, as this study is based on a single operating condition (summer peak), the researchers did not directly specify seasonal availability or dispatch.

These demand response projects, when dispatched, effectively represent a source of incremental energy. Each of the demand response resources for the 2005 Hobby system has a characteristic operating profile. To provide a basis for comparison of energy, loss, capacity, and emission impacts of the 2011 Hobby system demand response resources, the researchers assumed the entire portfolio of demand response resources was available at any time, but with limits on annual dispatch. The researchers used the demand response limits set forth Section 2.3.7. The researchers also assumed residential and small business HVAC cycling demand response would be called only during summer peak periods, and demand response resources of other customer classes would be called outside of summer peak periods.

The Optimal DER Portfolio for the 2005 Hobby system includes 1,396 distributed generation additions representing a total capacity of 35.206 MW. Each of these projects has a characteristic size and annual operating profile.

The Optimal DER Portfolio for the 2005 Hobby system also includes 1,488 distributed storage projects representing approximately 35 MW of on-peak capacity. Each of these has a characteristic size. Storage projects are net consumers of energy but provide energy during periods when it has high value based on the seasonal energy values the researchers are using, and consume energy during low-value periods. The storage also yielded congestion relief or location value during peak periods.

For the 2011 Hobby system, the researchers identified 3,000 Optimal DER Portfolio distributed generation additions for the 2011 Hobby system using the same approach; these represent 46.86 MW of nominal capacity.

As the 2011 study is based on a single operating condition (summer peak), the researchers did not directly specify seasonal availability or dispatch of the dispatchable projects within this portfolio. To provide a basis for comparison of energy, loss, capacity, and emission impacts, the researchers assumed all the dispatchable projects within each type and customer class had the same operating profile as the 2005 Optimal DER Portfolio distributed generation projects in aggregate within that same type and customer class.

According to the researchers' approach, storage projects are identified based on a combined assessment of their on-peak incremental capacity and off-peak charging impacts. In the absence of an off-peak forecast case, the researchers did not develop a set of storage projects for the 2011 Hobby system.

Table 54 shows an annual valuation of equivalent energy production of the Optimal DER Portfolio projects when dispatched using the seasonal energy values stated in Section 2.3.7.

Table 55 shows the valuation of the congestion relief or location premium associated with the energy produced by these projects using the values stated in Section 2.3.7.

Table 54. Energy value of Optimal DER Portfolio projects

Hobby System	Type	Capacity	Annual Value
November 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$318,606
"	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$1,580,053
"	1,396 DG Projects	26.2 MW	$15,343,293
"	1,488 Storage Projects	35 MW	$1,441,440
2011 Forecast	3,000 DR Projects	14.93 MW	$192,184
"	3,000 DG Projects	46.86 MW	$21,944,520

Table 55. Congestion/location value of Optimal DER Portfolio projects

Hobby System	Type	Nominal Capacity	Annual Value
November 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$2,138
"	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$10,577
"	1,396 DG Projects	35.206 MW	$104,460
"	1,488 Storage Projects	35 MW	$43,680
2011 Forecast	3,000 DR Projects	14.93 MW	$1,339
"	3,000 DG Projects	46.86 MW	$180,606

Hobby System	Type	Nominal Capacity	Annual Value

3.3.9. Loss Reduction

Nearly every network performance enhancement measure evaluated in this project has some impact on losses, and in fact, many of these measures are specified specifically for their loss impact (along with voltage).

The results in Section 3.2.3 show that ideal settings of existing controls can have a significant impact on losses. These results are restated in

Table 56; loss reductions shown are for the entire Hobby system, both transmission and distribution. These results reflect a systemwide optimization using GRIDfast™ of transformer taps, capacitor dispatch, and the VAR output of existing embedded generation with the objective of simultaneous minimization of real losses, reactive losses, and voltage deviation from nominal. The change is relative to the system with the "actual" configuration of those elements taken from system monitoring data.

As explained in Section 3.2.3, the researchers have applied the loss and voltage benefits of recontrols as applied to the September 2009 Hobby to the 2011 Hobby forecast case given the absence of "actual" control settings for the forecast case against which to assess, the impacts of revised control settings. It is important to note that the benefits of recontrols are function of the as-found state of the system's controls and how well-suited they are to the operating conditions; it does not necessarily follow that a more heavily loaded system will derive more benefit from ideal controls relative to business as usual.

Table 56 also shows an annual valuation of these losses using seasonal capacity and energy values in Sections 2.3.4 and 2.3.7, assuming the loss reductions associated with recontrols are realized through each set of operating conditions.

To extrapolate the recontrol loss benefit values obtained for the 2009 and 2011 forecast cases under summer peak conditions to annual values, the researchers assume the annual loss values are 45% of the summer peak value if extended through the entire year. This is consistent with the findings from the 2005 recontrol results.

Table 56. Loss impacts of recontrols

Hobby System	Operating Conditions	P Loss Reduction	P Loss Reduction Value
November 2005	Summer Peak	3.239 MW	$1,353,853
"	Winter Peak	1.304 MW	$171,113
"	Super-peak	2.445 MW	$157,650
"	Off-peak (Light Load Hour)	0.405 MW	$44,603
"	Off-peak (Minimum Load)	0.340 MW	$37,444
Annual Total			$1,764,663

Hobby System	Operating Conditions	P Loss Reduction	P Loss Reduction Value
September 2009	Summer Peak	1.383 MW	$408,883
2011 Forecast	Summer Peak	1.383 MW	$408,883

Recontrols as a system performance enhancement "measure" require a certain level of capacitor automation, with controls, sensing, and intelligence. The benefits from recontrols arise primarily from capacitor redispatch. More importantly, specific individual capacitors would have to be manipulated either daily or seasonally to achieve these results. In Section 3.2.3, the researchers showed that for the Hobby system in 2005, 559 of the 839 capacitors in the system would require condition-sensitive dispatch control, and 139 would require more simple daily on-off controls.

In Section 3.2.5, the researchers show that alternative topologies can have a significant impact on losses. The researchers showed a "portfolio" of 128 high-value, seasonally varying networking switch closures for the 2005 Hobby system that yield a significant share of the potential benefits of networked topology, while retaining an essentially radial topology. The researchers identified a portfolio of 14 high-value networking switch closures under the 2011 forecast case's summer peak conditions using the same approach. These results are summarized in

Table 57. In each case, the benefit shown is the incremental improvement of an optimized case incorporating the identified switch closures compared to an optimized case without any networking. The 2011-forecast case is much more heavily loaded than the 2005 case, providing more potential to improve network performance though redistribution of loads through networking.

Table 57 also shows an annual valuation of these losses using the energy and capacity values stated earlier, assuming the loss reductions associated with networking are realized through each set of operating conditions.

To extrapolate the networking loss benefit values obtained for 2011-forecast case under summer peak conditions to annual values, the researchers assume the annual loss values are 33% of the summer peak value if extended through the entire year. This is consistent with the findings from the 2005 networking results.

Table 57. Loss impacts of "Networking Portfolio" of high-value switch closures

Hobby System	Operating Conditions	P Loss Reduction (MW)	P Loss Reduction Value
November 2005	Summer Peak	1.320	$551,740
"	Winter Peak	0.210	$25,388
"	Super-peak	1.05	$73,484
Annual Total			$650,613
2011 Forecast	Summer Peak	4.0537	$878,883

Networking as a system performance enhancement “measure” requires a certain level of switch automation. Each of these “networking portfolios” identifies specific individual switches that would have to be closed under certain operating conditions to achieve the results shown.

Implementation of networked or “looped” topology introduces additional concerns in terms of fault protection and the ability to return to a radial configuration under certain circumstances. The researchers have not attempted to address these here. The researchers’ view is that a small number of high-value networking or looping opportunities, once identified, may warrant the further analysis that would be required for implementation.

The Optimal DER Portfolio for the 2005 Hobby system presented in Section 3.2.6 includes 157 capacitor additions representing a total capacity of 42.15 kVAR. In Section 3.2.6, the researchers also identified three Optimal DER Portfolio capacitor additions for the 2011 Hobby system. The loss impacts of these capacitor additions are summarized in Table 58. In each case, the benefit shown is the incremental improvement of an optimized case incorporating the capacitor additions compared to an optimized case without any capacitor additions. Table 58 also shows an annual valuation of these losses using the allocated avoided loss values stated earlier.

To extrapolate the capacitor addition loss benefit values obtained for 2011-forecast case under summer peak conditions, the researchers assume the annual loss values are 10% of the summer peak value if extended through the entire year. This is consistent with the findings from the 2005 Optimal DER Portfolio results.

Table 58. Loss impacts of Optimal DER Portfolio Capacitor additions

Hobby System	Operating Conditions	P Loss Reduction (MW)	P Loss Reduction Value
November 2005	Summer Peak	0.417	$174,234
“	Winter Peak	0.027	$3,248
“	Super-peak	-0.309	($21,602)
“	Off Peak	-0.179	($37,265)
Annual Total			$118,615
2011 Forecast	Summer Peak	2.3056	$151,477

The Optimal DER Portfolio for the 2005 Hobby system includes 22,147 demand response additions, representing a total capacity of 8.5 MW, and 128.7 MW under super-peak conditions. The researchers also presented a more rarified portfolio of the 4,192 highest-value demand response additions representing a total capacity of 4.9 MW, and 31.8 MW under super-peak conditions. The latter set of projects was selected for both their loss impact and their voltage impact. For these projects, the researchers restricted operation of the large number of residential and small business HVAC cycling projects to super-peak conditions, hence the difference in the available capacity.

The researchers identified 3,000 Optimal DER Portfolio demand response additions for the 2011 Hobby system; these represent 14.93 MW. Because this portfolio was also selected based on both loss and voltage impacts, it is most analogous to the smaller portfolio from the 2005 studies. However, as this study is based on a single operating condition (summer peak), the researchers did not directly specify seasonal availability or dispatch.

To provide a basis for comparison of energy, loss, capacity, and emission impacts, the researchers assumed the entire portfolio of demand response resources was available at any time, but with limits on annual dispatch. The researchers used the demand response limits set forth in Section 2.3.7. The researchers also assumed residential and small business HVAC cycling demand response would be called only during summer peak periods, and demand response resources of other customer classes would be called outside of summer peak periods.

Table 59 shows an annual valuation of the impacts of these projects using the seasonal capacity and energy values stated earlier, assuming the loss reductions associated with networking are realized through each set of operating conditions.

Table 59. Loss impacts of Optimal DER Portfolio demand response additions

Hobby System	Type	Nominal Capacity	P Loss Reduction Value
November 2005	4,192 DR Projects	4.9 MW (31.8 MW super-peak)	$274,879
“	22,147 DR Projects	8.5 MW (128.7 MW super-peak)	$865,975
2011 Forecast	3,000 DR Projects	14.93 MW	$186,962

The Optimal DER Portfolio for the 2005 Hobby system includes 1,396 distributed generation additions representing a total capacity of 35.206 MW. Each of these projects has a characteristic size and annual operating profile.

The researchers also identified 3,000 Optimal DER Portfolio distributed generation additions for the 2011 Hobby system using the same approach; these represent 46.86 MW of nominal capacity.

As this study is based on a single operating condition (summer peak), the researchers did not directly specify seasonal availability or dispatch of the dispatchable projects within this portfolio. To provide a basis for comparison of energy, loss, capacity, and emission impacts, the researchers assumed all the dispatchable projects within each type and customer class had the same operating profile as the 2005 Optimal DER Portfolio distributed generation projects in aggregate within that same type and customer class.

The loss impacts of these resources are summarized in Table 60. Table 60 also shows an annual valuation of these losses using the seasonal capacity and energy values stated earlier, assuming the loss reductions associated with networking are realized through each set of operating conditions.

As noted above, the impacts of the Optimal DER Portfolio distributed generation projects for the 2005 Hobby system are stated relative to the system already populated with capacitor additions and demand response. Therefore, the impacts of the distributed generation projects are attenuated somewhat. In addition, the distributed generation projects in the Optimal DER Portfolio for the 2011 Hobby system represent a larger portfolio in terms of capacity and yield greater loss reduction due to the heavier loading of the system under forecast loads.

Table 60. Loss impacts of Optimal DER Portfolio distributed generation additions

Hobby System	Type	Capacity	P Loss Reduction Value
November 2005	1,396 DG Projects	26.2 MW	$1,258,581
2011 Forecast	3,000 DG Projects	46.86 MW	$2,812,764

The Optimal DER Portfolio for the 2005 Hobby system includes 1,488 distributed storage projects representing approximately 35 MW of on-peak capacity. Each of these has a characteristic size.

According to this project's approach, storage projects are identified based on a combined assessment of their on-peak incremental capacity and off-peak charging impacts. In the absence of an off-peak forecast case, the researchers did not develop a set of storage projects for the 2011 Hobby system.

Table 61 provides the loss impacts of these projects. As noted above, the impacts of the Optimal DER Portfolio distributed storage projects for the 2005 Hobby system are stated relative to the system already populated with capacitor additions, demand response, and distributed generation. Therefore, the impacts presented here for the distributed storage projects are attenuated.

Table 61. Loss impacts of Optimal DER Portfolio distributed storage

Type	Nominal Capacity	P Loss Reduction Value
1,488 Storage Projects	35 MW	$756,962

The results in Section 3.2.8 show that certain of the network expansion projects from the Hobby system capital plan have a significant impact on losses. These results are restated in

Table 62; again, loss reductions shown are for the entire Hobby system, both transmission and distribution.

Table 62 also shows an annual valuation of these losses using the allocated avoided loss values stated earlier. To extrapolate the loss benefit values obtained for these network expansion projects in the 2011-forecast case under summer peak conditions to annual values, the researchers assume the annual loss values are 45% of the summer peak value if extended through the entire year. This is consistent with the findings from the 2005 recontrol results.

Table 62. Loss impacts of network expansion projects

Hobby System	Operating Conditions	Project	P Loss Reduction (MW)	P Loss Reduction Value
2011 Forecast	Summer Peak	Caraval Ckt	0.0743	$21,967
"	"	Starling Ckt	-0.1718	($50,793)
"	"	Container Sub	1.8599	$549,879
"	"	Fastener Sub	3.0390	$898,480
"	"	Macaw Sub	1.8622	$550,559
"	"	Cloud Sub	1.6873	$498,850
"	"	Oyster Sub	0.2003	$59,219
"	"	Weckl Sub	3.4149	$1,009,615

3.3.10. Emissions Reduction

The researchers attributed emission reduction values to all network measures that result in loss reductions, and to the net energy production of PV distributed generation, demand response, and storage. The researchers used the combined emission reduction value established by NCI discussed in Section 2.3.9 to value this benefit. The results are shown in Table 63.

Table 63. Emission values of network measures

Hobby System	Measure	Annual Emission Reduction Value
November 2005	Recontrols	$11,279
"	Networking	$3,378
"	157 Capacitors	$328
"	22,147 DR Projects	$10,702
"	4,192 DR Projects	$2,384
"	1,396 DG Projects	$48,593
"	1,488 Storage Projects	($6,652)
2011 Forecast	Recontrols	$4,852
	Networking	$10,429
	3 capacitors	$1,798
"	3,000 DR Projects	$1,405
"	3,000 DG Projects	$132,755
"	Caraval Ckt	$579
"	Starling Ckt	($603)
"	Container Sub	$6,525
"	Fastener Sub	$10,662
"	Macaw Sub	$6,533
"	Cloud Sub	$5,920
"	Oyster Sub	$703
"	Weckl Sub	$11,981

3.3.11. Load Relief

By providing incremental electrical capacity and energy from within the power delivery system, DER can effectively increase the capacity or load-serving capability of the existing power delivery system, provided the DER is electrically linked to a constraint that would otherwise limit the load-serving capability of the system. Depending on anticipated growth and capital investment plans, incremental capacity, and energy from such, DER can defer the need for new capital investments, under the right circumstances and for a period. This project's approach is to evaluate both DER additions and system expansion projects in terms of specific load relief benefits. Load relief value for any network performance improvement measure is dependent on whether there is a) a real constraint in the system b) that would actually be relieved by the measure.

In the researchers' simulation of the Hobby system with 2011 loads, the researchers identified 15 substations whose loading will exceed their normal rating under the researchers' normal peak forecast loads in 2011. The researchers consider these "demonstrated" constraints, and measures that relieve these overloads can have load relief benefit. Measures that can increase the effective capacity of a substation would include load shifts, circuit expansion projects that remove load from a loaded substation, incremental capacity within the substation's circuits from DER, and substation expansion projects.

Load shifts identified in the Hobby capital plan will eliminate the overloads at 2 of the 15 substations, Weckl and Metal. Therefore, the researchers do not attribute a load relief benefit to other measures that may relieve the normal-condition overload at those two substations. The remaining "demonstrated" constraints are substation overloads at the following substations:

- Author 12 kV
- Boat 115/12 kV
- Bird 115/33 kV
- Oyster 12 kV
- Fish 12 kV
- Hawser 33/12 kV
- Music 115/12 kV
- Sail 115/33 kV
- Limpet P.T.
- Bobwhite P.T.
- Heron 12 kV
- Paint 115/12 kV
- Preventer 33/12 kV

In Section 3.2.5, the researchers described a "networking portfolio" of switch closures for the 2011 Hobby system; these are repeated in

Table 64.

Table 64. Hobby 2011 networking portfolio switch closures

Switch	Circuits Joined	Substations Joined	Systems Joined
PS0263	Violin-Griffon	Music-Dog	Music-Dog
PS1630	Horseshoe-Drum	Ride-Music	Ride-Music
BDS2332	Crow-Parrot	Owl-Sandpiper	
12160S	Vanadium-Mussel	Metal-Oyster	Metal-Shellfish
GS5028	Shrimp-Cadmium	Oyster-Metal	Shellfish-Metal
RCS1384	Clam-Burmese	Cockle-Balinese	Shellfish-Wildcat
RCS1965	Cedar-Sprint		
GS5511	Gull-Muscat	Puffin-Grape	Bird-Grape
RCS2224	Barbera-Reisling		
RCS7076	Muscat-Barbera		
PS0311	Drum-Bridle	Music-Ride	Music-Ride
PME5303	Bay-Guitar	Horse-Music	Horse-Music
PS1510	Ink-Orange	Paint-Fruit	Paint-Fruit
BS0007	Morrison-Decartes		

These switch closures were identified for their value in reducing losses and improving voltage. However, this set of networking switch closures may provide some load relief for identified substations Music and Paint. The load relief needed for Oyster substation, 21 MVA, would most likely not be meaningfully addressed through these networking switch closures.

Table 65 lists the aggregate capacity of the 3,000 2011 Optimal DER Portfolio distributed generation projects within each of the loaded substations listed above. In terms of load relief, the projects on circuits served from Music substation could provide a load relief benefit. The capacity of the distributed generation projects on circuits served from the Music substation is more than enough to eliminate the normal-condition overload on Music substation. Distributed generation projects on circuits served from Weckl and Metal substations are also enough to eliminate the normal-condition overloads on those substations under forecast loads. However, the overloads on both substations are also relieved through planned load shifts, so there is no incremental load relief value for the distributed generation capacity.

Table 65. 2011 Optimal DER Portfolio DG capacity in loaded substations

Loaded Substation	DG MW
Author	
Boat	4.831
Bird	7.853
Oyster	

Loaded Substation	DG MW
Fish	0.353
Hawser	0.599
Music	4.927
Sail	7.361
Limpet	
Bobwhite	0.238
Heron	
Paint	1.075
Preventer	0.652

Table 66 lists the aggregate capacity of the 3,000 Optimal DER Portfolio demand response projects within each of the loaded substations listed above. In terms of load relief, none of these sets of projects provides enough capacity to address the identified overloads of these substations. The demand response projects on circuits served from Weckl substation could possibly provide some load relief or capacity deferral benefit. The Weckl substation overload is only 1.28 MW. Accordingly, while this overload is resolved through a planned load shift, if loads develop less slowly, the demand response projects on circuits served from Weckl could also be enough to defer an overload condition.

Table 66. 2011 Optimal DER Portfolio DR capacity in loaded substations

Loaded Substation	DR MW
Author	0.144
Boat	0.640
Bird	1.466
Oyster	0.324
Fish	1.184
Hawser	
Music	1.011
Sail	0.336
Limpet	
Bobwhite	0.639
Heron	
Paint	
Preventer	0.317

The Hobby capital plan identifies substation transformer bank capital projects that would eliminate the demonstrated constraints at Music as well as at Heron and Paint, though the incremental capacity added in each of these projects goes well beyond the capacity deficit the researchers found.

As explained in Section 3.2.8, the researchers also simulated the impacts of selected network circuit and substation expansion projects from the Hobby capital plan. These would eliminate demonstrated overloads at one or more substations, in most cases. The load relief impacts of the capital plan transformer, circuit, and substation projects are listed in Table 67.

The researchers' simulations of the Starling circuit project and the Container substation project indicate that both relieve the overload of Metal substation; however, this constraint is also addressed through a planned load shift. The researchers' simulation of the Weckl substation project indicates that it relieves the overload of Weckl substation, also addressed through a planned load shift. Therefore, the researchers would not attribute load relief benefit to measures that relieve Metal and Weckl substations.

Table 67. Network expansion projects load relief

Project	Substation OL Relief
Caraval Ckt	
Starling Ckt	
Container Sub	Limpet
Fastener Sub	Bird, Bobwhite
Macaw Sub	Bird
Cloud Sub	Sail, Preventer
Oyster Sub	Oyster
Weckl Sub	
Music Xfr	Music
Heron Xfr	Heron
Paint Xfr	Paint
Ride Xfr	

In addition to demonstrated overloads at the substation level, the Hobby system has nominal overloads of individual circuit line segments under the 2011 forecast loads. Where these loads exceed 120% of normal rated capacity, the researchers ascribe an elevated outage risk for purposes of assessing reliability. More modest circuit-level line segment overloads may well be dealt with through load shifts not specifically called out in the capital plan, thus the value of relieving such overloads is likely small. The researchers identified DER on seven circuits, Drum, Brig, Sprint, Bridle, Riesling, Junco, and Mussel, with sufficient capacity to eliminate normal-condition overloads on those circuits.

The value of the load relief provided by these projects in dollar terms is stated in Table 68. In each case, the dollar value of the load relief is the annualized cost of the project that provides the relief. The researchers use NCI's value of 15% for the annual carrying cost of a capital investment that addresses a demonstrated constraint to yield an annual recurring value for that load relief.

The Music transformer project and the DER projects on circuits served from the Music substation both derive load relief benefit from the same source – mitigating the normal-condition overload on Music substation, so these values are duplicative. In both cases, the value of this load relief is based on the cost of the Music transformer project. The DER projects on circuits served from the Music substation represent about 48% of the capacity of the transformer bank, so arguably they represent 48% of the load relief of the transformer.

Table 68. Load relief benefits

Project	Load Relief Value ($/yr)
Caraval Ckt	
Starling Ckt	
Container Sub	$4,800,000
Fastener Sub	$1,950,000
Macaw Sub	$2,700,000
Cloud Sub	$5,100,000
Oyster Sub	$3,750,000
Weckl Sub	
Music Xfr	$671,850
Heron Xfr	$900,000
Paint Xfr	$900,000
Ride Xfr	
Flute Ckt DER Projects	$38,000
Guitar Ckt DER Projects	$73,000
Trombone Ckt DER Projects	$68,000
Music DER Projects (balance of ckts)	$151,000

Repeating two important observations, first, the researchers did not attribute load relief value to every network expansion project, either because the researchers did not find they relieved demonstrated constraints (at least in the 2011 Hobby simulation) or that the constraint they relieve would also be relieved (at least in 2011) by a planned load shift. Second, all of the 13 substations with a demonstrated constraint listed above are addressed.

This analysis would be improved if extended over several years, each with a simulation incorporating that year's forecast loads. This would clearly show how expected load growth over time affects the relative merits of DER vs. a substation expansion project.

These results suggest that it is relatively difficult for DER resources to relieve substation overloads or defer substation expansion projects. However, it is important to keep in mind that the DER projects were identified for their loss and voltage benefits, and load relief is an indirect benefit. In addition, the researchers limit the penetration of DER (particularly DG) to about 15% of peak load, as described in Section 2.2.6. It appears that these substation projects often provide much larger increments of load-serving capability.

3.3.12. Benefit-Cost Ranking

Recontrols

In Sections 3.3.2 through 3.3.11 the researchers showed that recontrols have quantified and valuable benefits in several benefit categories. These are summarized for recontrols in Table 69 below.

Table 69. Aggregate benefits of recontrols

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
November 2005	Recontrols	$434,783	$42,540	$1,764,663	$11,279
2011 Forecast	Recontrols	$654,912	$13,278	$408,883	$4,852

Alternate Topology

In Sections 3.3.2 through 3.3.11, the researchers estimated the network benefits of "networking portfolios" of selected switch closures for the 2005 and 2011 Hobby systems in several different benefit categories. These are summarized for alternate topologies in Table 70 below.

Table 70. Aggregate benefits of networking portfolio switch closures

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
November 2005	Networking	$416,281	$40,969	$650,613	$3,378
2011 Forecast	Networking	-	-	$878,883	$10,429

Capacitor Additions

In Sections 3.3.2 through 3.3.11, the researchers showed the benefits in several benefit categories of Optimal DER Portfolio capacitor additions for the 2005 and 2011 Hobby systems. These are summarized for capacitor additions in Table 71.

Table 71. Aggregate benefits of Optimal DER Portfolio capacitor additions

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)

November 2005	157 Capacitors	-		$118,615	$328
“	22 “Voltage Benefit” Capacitors	$740,056	$72,348		
2011 Forecast	3 Capacitors	$241,814	$4,903	$151,477	$1,798

DER Additions

In Sections 3.3.2 through 3.3.11, the researchers showed the benefits of Optimal DER Portfolio resource additions in several benefit categories. The benefits of capacitor additions were summarized above. The benefits of demand response, distributed generation, and storage additions are summarized in the following tables. Table 72 continuing to Table 73, Table 74 continuing to Table 75 , and Table 76 continuing to Table 77 summarize the aggregate benefits of the 2005 and 2011 Optimal DER Portfolio demand response, distributed generation, and storage additions, respectively. The benefits, shown as attributed to the projects as a group, actually differ from project to project based on the dispatch profile of each project.

Table 72. Aggregate benefits of Optimal DER Portfolio demand response (A)

Hobby System	Type	Bulk System Capacity Value ($/yr)	Ancillary Services Value ($/yr)	Energy Value ($/yr)	Congestion Relief Value ($/yr)
November 2005	4,192 DR Projects	$2,085,673	$381,330	$318,606	$2,138
“	22,147 DR Projects	$7,792,560	$714,132	$1,580,053	$10,577
2011 Forecast	3,000 DR Projects	$984,148	$671,962	$192,184	$1,339

Table 73. Aggregate benefits of Optimal DER Portfolio demand response (B)

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
November 2005	4,192 DR Projects	$9,251	-	$274,879	$10,702
“	22,147 DR Projects	-	-	$865,975	$2,384
2011 Forecast	3,000 DR Projects	$324,937	-	$186,962	$48,593

Table 74. Aggregate benefits of Optimal DER Portfolio distributed generation (A)

Hobby	Type	Bulk System	Energy Value	Congestion Relief

System		Capacity Value ($/yr)	($/yr)	Value ($/yr)
November 2005	1,396 DG Projects	$3,311,988	$15,343,293	$104,460
2011 Forecast	3,000 DG Projects	$3,198,992	$21,944,520	$180,606

Table 75. Aggregate benefits of Optimal DER Portfolio distributed generation (B)

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
November 2005	1,396 DG Projects	$333,025	$32,557	$1,258,581	$48,593
2011 Forecast	3,000 DG Projects	$554,156	$11,235	$2,812,764	$132,755

Table 76. Aggregate benefits of Optimal DER Portfolio distributed storage (A)

Hobby System	Type	Bulk System Capacity Value ($/yr)	Ancillary Services Value ($/yr)	Energy Value ($/yr)	Congestion Relief Value ($/yr)
November 2005	1,488 Storage Projects	$3,573,603	$270,000	$1,441,440	$43,680

Table 77. Aggregate benefits of Optimal DER Portfolio distributed storage (B)

Hobby System	Type	Power Quality ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
November 2005	1,488 Storage Projects	$1,850	-	$756,962	($6,652)

The researchers found specific subsets of DER projects within each Optimal DER Portfolio in specific locations or with specific attributes that have additional network benefits. These subsets are summarized in the following discussion.

Table 78 summarizes the system voltage security benefit of the large quantity of small business and residential HVAC cycling demand response projects in the greater demand response portion of the 2005 Optimal DER Portfolio. These are the only resources to which the researchers attribute a system voltage security benefit. The demand response projects in the

2011 Optimal DER Portfolio do not represent enough capacity to provide this benefit. For the named projects this benefit is additive to their other benefits.

Table 78. Additional benefits of specific Optimal DER Portfolio demand response

Hobby System	Type	System Voltage Security Value ($/yr)
November 2005	18,842 HVAC Cycling DR Projects	$90,000

Table 79 summarizes the reliability benefits of 2005 Optimal DER Portfolio demand response projects sited on specific named circuits. Table 80 summarizes the reliability benefits of 2005 Optimal DER Portfolio distributed generation projects sited on specific named circuits.

Table 81 summarizes the reliability benefits of 2011 Optimal DER Portfolio DER projects sited on specific named circuits.

Table 79. Additional benefits of specific 2005 Optimal DER Portfolio demand response

Hobby System	Type	Customer Reliability Value ($/yr)	Utility/Ratepayer Reliability Value ($/yr)
November 2005	Spur Ckt DR Projects	$513	$640
“	Chromium Ckt DR Projects	$372	$205
“	Apple Ckt DR Projects	$2,362	$3,180
“	Lynx Ckt DR Projects	$3,167	$1,535
“	Peach Ckt DR Projects	$200	$330

Table 80. Additional benefits of Specific 2005 Optimal DER Portfolio distributed generation

Hobby System	Type	Customer Reliability Value ($/yr)	Utility/Ratepayer Reliability Value ($/yr)
November 2005	Blanket Ckt DG Projects	$52,927	$35,135
“	Net Ckt DG Projects	$37,515	$50,925

Table 81. Additional benefits of specific Optimal DER Portfolio DER

Hobby System	Type	Customer Reliability Value ($/yr)	Utility/Ratepayer Reliability Value ($/yr)
2011 Forecast	Sloop Ckt DER Projects	$374,298	$168,045

Hobby System	Type	Customer Reliability Value ($/yr)	Utility/Ratepayer Reliability Value ($/yr)
"	Yawl Ckt DER Projects	$312,869	$241,010
"	Wrasse Ckt DER Projects	$351,317	$231,820
"	Barbera Ckt DER Projects	$80,579	$43,905
"	Muscat Ckt DER Projects	$192,186	$116,295
"	Riesling Ckt DER Projects	$257,261	$196,290
"	Roan Ckt DER Projects	$181,103	$157,930
"	Rich Ckt DER Projects	$38,431	$51,660
"	Cadmium Ckt DER Projects	$139,321	$100,640
"	Chromium Ckt DER Projects	$288,469	$160,040
"	Brecker Ckt DER Projects	$345,037	$153,920
"	Carter Ckt DER Projects	$63,066	$102,480
"	Flute Ckt DER Projects	$65,025	$36,990
"	Guitar Ckt DER Projects	$141,667	$101,170
"	Trombone Ckt DER Projects	$154,625	$132,935
"	Smock Ckt DER Projects	$599,087	$288,270
"	Watercolor Ckt DER Projects	$464,307	$257,655
"	Exclusion Ckt DER Projects	$76,686	$82,055
"	Bridle Ckt DER Projects	$78,762	$36,590
"	Saddle Ckt DER Projects	$255,148	$258,015
"	Spur Ckt DER Projects	$260,203	$234,345
"	Dinghy Ckt DER Projects	$232,629	$180,130
"	Mussel Ckt DER Projects	$141,155	$83,395
"	Cedar Ckt DER Projects	$217,908	$144,805
"	Panther Ckt DER Projects	$62,834	$76,620

As discussed in Section 3.3.1, the DER projects in the 2011 Optimal DER Portfolio represent more than enough capacity to eliminate the normal-condition overload on Music substation, a demonstrated constraint in the 2011 Hobby system. The load relief benefit for the Music circuit DER projects as a group is $335,000, allocated as shown in Table 82.

Table 82. Additional benefits of Specific Optimal DER Portfolio DER

Hobby System	Type	Load Relief Value ($/yr)
2011 Forecast	Flute Ckt DER Projects	$38,000
"	Guitar Ckt DER Projects	$78,000
"	Trombone Ckt DER Projects	$68,000
"	Remaining Music Sub DER Projects	$151,000

Network Expansion Projects

In Sections 3.3.2 through 3.3.11, the researchers estimated the benefits in several benefit categories from the individual network expansion projects from the Hobby system capital plan that the researchers analyzed. These results are summarized for network expansion projects in

Table 83 continuing to Table 84. The load relief values are the annualized costs of each of the projects that provide relief for demonstrated constraints.

Table 83. Utility network expansion projects benefits (A)

Hobby System	Project	Power Quality Value ($/yr)	CVR Value ($/yr)	P Loss Reduction Value ($/yr)	Emission Reduction Value ($/yr)
2011 Forecast	Caraval Ckt			$21,967	$579
"	Starling Ckt			($50,793)	($603)
"	Container Sub			$549,879	$6,525
"	Fastener Sub			$898,480	$10,662
"	Macaw Sub	$118,388	$2,400	$550,559	$6,533
"	Cloud Sub			$498,850	$5,920
"	Oyster Sub			$59,219	$703
"	Weckl Sub	$105,793	$2,145	$1,009,615	$11,981
"	Music Xfr				
"	Heron Xfr				
"	Paint Xfr				
"	Ride Xfr				

Table 84. Utility network expansion projects benefits (B)

Hobby System	Project	Reliability Impact in Customer VOS ($/yr)	Reliability Impact in Utility/Ratepayer VOS ($/yr)	Load Relief Value ($/yr)
2011 Forecast	Caraval Ckt			
“	Starling Ckt			
“	Container Sub			$4,800,000
“	Fastener Sub			$1,950,000
“	Macaw Sub	$146,087	$117,495	$2,700,000
“	Cloud Sub	$39,667	$20,695	$5,100,000
“	Oyster Sub			$3,750,000
“	Weckl Sub	$28,383	$7,010	
“	Music Xfr			$671,850
“	Heron Xfr			$900,000
“	Paint Xfr			$900,000
“	Ride Xfr	$9,214	$10,220	

It is important to note that the load relief value shown here for the Music transformer project includes the load relief value attributed above to the Music circuit DER projects.

2005 Network Measures Summary

Table 85 below, adapted from the NCI study, shows each benefit category by stakeholder. Utility (U) refers to the utility or network operator. Utility benefits are financial benefits that accrue directly to the utility. Utility/Ratepayer (U/R) refers to benefits that accrue initially to the utility but ultimately to all customers of the utility in the form of reduced costs. Customer (C) benefits accrue directly to the customers of the utility. Strictly speaking these benefits, reliability and power quality, would accrue only to the customers within the subject system. Societal (S) benefits accrue to society at large and are not limited to the subject system.

Table 85. Benefit categories by stakeholder

Benefit Category	U	U/R	C	S
Reliability		X	X	
Power Quality			X	
Bulk System Capacity		X		
Ancillary Services Capacity		X		
System Voltage Security		X		
Energy		X		
Losses		X		
Emissions Reductions				X
Load Relief	X			
CVR		X		

Source: NCI

Under this project's assumption that the "utility" costs of all network enhancement projects are recovered from customers, the utility as an economic actor should give a high economic rank to projects that have high combined utility and utility/ratepayer benefits relative to their cost. Under the present incentive structure, pure customer and societal benefits do not figure directly into spending decisions.

The capacitor additions (and any network expansion projects) are capital projects funded by the utility with costs recovered from customers in rates. Such projects whose "utility + utility ratepayer" value exceeds their annualized cost are arguably cost-effective; this is indicated by a cost-benefit ratio. For the 2005 projects, these values are listed in

Table 86. The annualized cost values are derived from the total cost of each project, annualized at a 15% carrying cost. The total cost of the capacitor installations is based on a value provided by NCI of $10/kVAR.

The 22 "voltage benefit" capacitor projects are a subset of the 157-capacitor additions but represent incremental value due to their impact on power quality and CVR.

Table 86. Utility capital project benefits and benefit-cost ratio

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)	Annualized Cost ($/yr)	Utility Benefit-Cost Ratio
2005	157 Capacitors	$328	$118,615	$63,225	1.9
"	22 Voltage Benefit Capacitors	$740,056	$72,348		

The recontrols, alternate topology/networking, and demand response dispatch projects are also measures that would be exclusively utility- or network operator-funded. However, these projects are largely operational in nature, though they would likely have costs in the form of additional distribution automation. In the case of the 2005 Hobby system, all three measures are shown to provide network benefits; their aggregate value is shown in

Table 87.

Table 87. Utility operational projects benefits

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)
2005	Recontrols	$446,062	$1,807,167
“	Networking	$419,659	$691,309
“	Coordinated dispatch of top 1,000 existing DR	$64,755	$0

The Optimal DER Portfolio projects (other than capacitor additions) could be utility/ratepayer-funded, or they could be customer-funded, depending on the business model. Further, the energy benefit category can be large, especially for DG, and potentially distorting. For these projects, the researchers show their total value and the total utility + utility/ratepayer value, excluding energy. The researchers also show the latter value expressed in terms of the nominal capacity of the projects. This provides a basis for comparison of these sets of projects in terms of their network benefits in lieu of a true cost-benefit ratio. These results are shown in

Table 88.

Table 88. Optimal DER Portfolio Project benefits

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)	Total U + U/R Value Excl. Energy ($/yr)	Total U + U/R Value Excl. Energy ($/kWyr)
2005	22,147 DR Projects	$10,702	$10,963,297	$9,383,244	$71
“	4,192 DR Projects	$11,635	$3,062,626	$2,744,020	$81
“	1,396 DG Projects	$381,618	$20,050,879	$4,707,586	$134
“	1,488 Storage Projects	($4,802)	$6,085,865	$4,644,425	$133

The 4,192 demand response projects in

Table 88 are a subset within the full set of 22,147 demand projects; the smaller group contributes additional value due to these projects’ voltage impacts.

Among the 2005 Optimal DER Portfolio projects, there are subsets of demand response and distributed generation projects that provide additional value due to their location or operating characteristics. The incremental value attributed to the HVAC demand response projects is due to their contribution to system voltage security. For the remainder of the projects, their incremental value is due to their reliability impact. These projects and their incremental value are summarized in Table 89.

Table 89. Additional benefits of specific Optimal DER Portfolio projects

Hobby System	Type	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)	Total U + U/R Value ($/kWyr)
2005	18,842 HVAC DR Projects	$0	$90,000	$1
"	Blanket Ckt DG Projects	$52,927	$35,135	$28
"	Net Ckt DG Projects	$37,515	$50,925	$87
"	Spur Ckt DR Projects	$513	$640	$20
"	Chromium Ckt DR Projects	$372	$205	$0
"	Apple Ckt DR Projects	$2,362	$3,180	$374
"	Lynx Ckt DR Projects	$3,167	$1,535	$3
"	Peach Ckt DR Projects	$200	$330	$2

For the 2005 system, these results suggest that the capacitor additions, particularly those with voltage benefits, are clearly valuable relative to their relatively low cost. The recontrols and networked topology projects appear to be compelling, particularly if their implementation cost is modest. The recontrols' and networking projects' primary value comes from their loss reduction. From the standpoint of a broader set of stakeholders, the voltage benefit capacitors, recontrols, and networked topology projects also deliver significant value due to voltage and impact on power quality.

The majority of the DER projects' value comes from bulk capacity. The large-penetration demand response portfolio does not appear to deliver compelling incremental benefits relative to the smaller demand response portfolio. The incremental value associated with enhanced system voltage security, available only with the larger demand response portfolio, is small, and smaller (4,192 projects) demand response portfolio represents greater value due to its voltage impacts. The portfolio of distributed generation projects provides additional value due to sustained loss reductions. The distributed generation projects also represent significant value in terms of customer benefits, primarily power quality improvement.

The results shown in Table 89 suggest that reliability improvement could be a significant driver for those DER projects in situated locations where they provide those benefits. The benefits of the demand response projects on the Apple circuit appear very large (and may not be realistic) because they yield a significant reliability benefit and represent only 9 kW.

2011 Network Measures Summary

The capacitor additions and the network expansion projects are capital projects funded by the utility with costs recovered from customers in rates. Such projects whose “utility + utility ratepayer” value exceeds their annualized cost are arguably cost-effective; this is indicated by a cost-benefit ratio. For the 2011 projects, these values are listed in Table 90. The annualized cost values derived from the total cost of each project stated in the Hobby system capital plan, annualized at a 15% carrying cost. The total cost of the capacitor installations is based on NCI’s value of $10/kVAR.

Table 90. Utility capital projects benefits

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)	Annualized Cost ($/yr)	Utility Benefit-Cost Ratio
2011 Forecast	3 Capacitors	$243,612	$156,380	$1,350	115.8
“	Caraval Ckt	$579	$21,967	$300,000	0.1
“	Starling Ckt	($603)	($50,793)	$300,000	-0.2
“	Container Sub	$6,525	$5,349,879	$4,800,000	1.1
“	Fastener Sub	$10,662	$2,848,480	$1,950,000	1.5
“	Macaw Sub	$271,008	$3,370,454	$2,700,000	1.2
“	Cloud Sub	$45,587	$5,619,545	$5,100,000	1.1
“	Oyster Sub	$703	$3,809,219	$3,750,000	1.0
“	Weckl Sub	$146,157	$1,018,770	$1,950,000	0.5
“	Music Xfr	$0	$671,850	$671,850	1.0
“	Heron Xfr	$0	$900,000	$900,000	1.0
“	Paint Xfr	$0	$900,000	$900,000	1.0
“	Ride Xfr	$9,214	$10,220	$300,000	0.0

It is important to reiterate that the load relief benefit attributed to the Music transformer project is duplicative of the load relief benefit attributed the Music DER projects.

The recontrols and alternate topology projects are also measures that would be exclusively utility- or network operator-funded. However, these projects are largely operational in nature, though they would likely have costs in the form of additional distribution automation. In the case of the 2011 Hobby system, both projects are shown to provide network benefits; their aggregate value is shown in Table 91.

Table 91. Utility operational projects benefits

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)
2011 Forecast	Recontrols	$659,764	$422,161
"	Networking	$10,429	$878,883

The Optimal DER Portfolio projects (other than capacitor additions) could be utility/ratepayer-funded, or they could be customer-funded, or some combination, depending on the business model. Further, the energy benefit category can be large, especially for DG, and potentially distorting. For these projects, the researchers show their total value, and the total utility + utility/ratepayer value excluding energy. The researchers also show the latter value expressed in terms of the nominal capacity of the projects. This provides a basis for comparison of these projects in terms of their network benefits in lieu of a true cost-benefit ratio. These results are shown in Table 92.

Table 92. Optimal DER Portfolio project benefits

Hobby System	Project	Total Customer + Society Value ($/yr)	Total Utility + Utility Ratepayer Value ($/yr)	Total U + U/R Value Excl. Energy ($/yr)	Total U + U/R Value Excl. Energy ($/kWyr)
2011 Forecast	3,000 DR Projects	$326,342	$2,036,595	$1,844,411	$124
"	3,0000 DG Projects	$686,911	$28,148,117	$6,203,597	$132

Among the 2011 Optimal DER Portfolio projects, there are subsets of demand response and distributed generation projects that provide additional value due to their location or operating characteristics. The Music circuits DER projects and the Flute, Guitar, and Trombone circuits DER projects provide additional value for load relief of the Music substation. For the remainder of the projects, their incremental value is due to their reliability impact. These projects and their incremental value are summarized in Table 93 and Table 94.

Table 93. Additional benefits of specific Optimal DER Portfolio projects

Hobby System	Project	Total Customer + Society Value ($/yr)	Total U + U/R Value Excl. Energy ($/yr)	Total U + U/R Value Excl. Energy ($/kWyr)
2011 Forecast	Music DER Projects (balance of circuits)	$0	$151,000	$56

Table 94. Additional benefits of specific Optimal DER Portfolio DER increments

Hobby System	Type	Total Customer + Society Value ($/yr)	Total U + U/R Value Excl. Energy ($/yr)	Total U + U/R Value Excl. Energy ($/kWyr)
2011 Forecast	Sloop Ckt DER Projects	$374,298	$168,045	$189
"	Yawl Ckt DER Projects	$312,869	$241,010	$129
"	Wrasse Ckt DER Projects	$351,317	$231,820	$835
"	Barbera Ckt DER Projects	$80,579	$43,905	$59
"	Muscat Ckt DER Projects	$192,186	$116,295	$75
"	Riesling Ckt DER Projects	$257,261	$196,290	$122
"	Roan Ckt DER Projects	$181,103	$157,930	$225
"	Rich Ckt DER Projects	$38,431	$51,660	$88
"	Cadmium Ckt DER Projects	$139,321	$100,640	$187
"	Chromium Ckt DER Projects	$288,469	$160,040	$698
"	Brecker Ckt DER Projects	$345,037	$153,920	$206
"	Carter Ckt DER Projects	$63,066	$102,480	$360
"	Flute Ckt DER Projects	$65,025	$74,990	$108
"	Guitar Ckt DER Projects	$141,667	$174,170	$132
"	Trombone Ckt DER Projects	$154,625	$200,935	$165
"	Smock Ckt DER Projects	$599,087	$288,270	$418
"	Watercolor Ckt DER Projects	$464,307	$257,655	$668
"	Exclusion Ckt DER Projects	$76,686	$82,055	$160
"	Bridle Ckt DER Projects	$78,762	$36,590	$67

Hobby System	Type	Total Customer + Society Value ($/yr)	Total U + U/R Value Excl. Energy ($/yr)	Total U + U/R Value Excl. Energy ($/kWyr)
“	Saddle Ckt DER Projects	$255,148	$258,015	$283
“	Spur Ckt DER Projects	$260,203	$234,345	$493
“	Dinghy Ckt DER Projects	$232,629	$180,130	$186
“	Mussel Ckt DER Projects	$141,155	$83,395	$337
“	Cedar Ckt DER Projects	$217,908	$144,805	$143
“	Panther Ckt DER Projects	$62,834	$76,620	$134

For the 2011 system, these results again suggest that the capacitor additions with voltage benefits are clearly valuable relative to their relatively low cost. The recontrols and networked topology projects similarly appear to be compelling, particularly if their implementation cost is modest. Again, the recontrols' and networking projects' primary value comes from their loss reduction. From the standpoint of a broader set of stakeholders, the capacitors and recontrols projects also deliver significant value due to their voltage impacts and impact on power quality. In this case, the networked topology did not have the compelling voltage benefits of the 2005-networking portfolio.

Because the researchers valued substation load relief at the cost to provide the relief, network expansion projects that provided only substation load relief would have by definition a cost-benefit ratio of 1.0. Accordingly, projects with higher cost-benefit ratios, such as the Fastener and Macaw substation projects, are those with significant contributions in other benefit categories. Of these projects, Fastener and Macaw had relatively high loss reduction value along with relatively low capital costs. Further, network expansion projects that do not relieve demonstrated constraints are burdened, in effect, by their cost with no offsetting benefit. For example, Weckl substation has considerable benefits; but it did not receive credit for any substation load relief because Weckl is nominally relieved through a planned load shift.

It is worth noting that the significant voltage benefits of the Macaw and Weckl substation projects do not figure into their utility cost-benefit ratio because power quality is considered a customer benefit and the researchers placed a relatively low value on CVR.

Again, the majority of the DER projects' value comes from bulk capacity. The portfolio of distributed generation projects provides additional value due to sustained loss reductions. The distributed generation projects also represent significant value in terms of customer benefits, primarily power quality improvement.

The results shown in Table 93 and Table 94 suggest that reliability improvement could be a significant driver for those DER projects in situated locations where they provide those benefits.

The “Total Utility + Utility/Ratepayer” results presented in Tables 90 through 94 offer a direct, side-by-side, objective comparison of the merits of a diverse set of network measures in dollars-per-year terms. These measures range from operational (ideal controls and topology reconfiguration) to traditional (new circuits and substations) to non-traditional (distributed energy resources). These results clearly show that the benefits of such diverse measures can be quantified and priced, and that rigorous project justification, even for new smart grid measures are possible.

3.3.13. Business Models

In a cost-recovery regulatory regime, network operators have a direct financial incentive to incur capital costs, an indirect incentive to reduce operating costs, and very weak incentives to incur any risk in seeking to capture network operational benefits from new approaches. Measures such as capacitor additions and network expansion capital projects represent established, proven approaches, benefit from a direct financial incentive as their costs are added to the utility’s rate base, and generate earnings. The projects identified in Section 3.3.12 as having positive utility cost-benefit ratios represent a straightforward investment decision.

Of the network measures summarized in Section 3.3.12, several have high value in terms of network performance benefits and low or no capital cost and can be implemented unilaterally by the network operator. These include recontrols and the alternate topologies, possibly along with focused distribution automation initiatives to implement these measures. As shown in Section 3.3.12, some of these projects can have very substantial total benefits. The business model needed to capture the potential value associated with these measures would entail promotion of and compensation for network measures adopted by network operators that do not involve substantial capital investments, and may carry some risk.

A second broad set of network performance improvement measures evaluated in Section 3.3.12 includes projects with greater institutional hurdles, as they may not necessarily involve a significant utility capital investment, but they may require cooperation with third parties. These include the Optimal DER Portfolio distributed generation and demand response projects. The researchers findings indicate that these projects represent significant value in terms of network benefits. This value derives from a broad set of benefit categories and may extend to multiple stakeholders; in particular, DER projects with network benefits may also represent additional benefit to their sponsors.

Ideally, the costs of such projects would be offset by all available benefit streams, making truly beneficial projects more apparent and more attractive to any one decision-maker. The researchers’ approach can determine objectively these benefits and their values, a necessary first step in exchanging value associated with these benefits among stakeholders. The per-kWyr values provided in Section 3.3.12 suggest that some projects provide significant network benefits in dollar terms. If these benefits figured into the project economics for customer or third-party developers, they could make a significant contribution to the economic viability of those projects.

Possibly the most important conclusion of the SVP Project was that while DER can enhance grid performance, the ability of individual projects to provide these benefits is highly location-dependent. Even though projects are identified by class or group, or circuit, the posited grid benefits attributed to that group assume each individual project is sited in a particular location and has particular operating characteristics. DER projects on the Mussel circuit represent $337/kWyr in total benefits in the 2011 Hobby system, but those benefits are only attributable to certain projects in certain locations on the Mussel circuit having specific attributes. Accordingly, any consideration of business models to capture such benefits from DER must include identification of these locational differences and communicating these differences to decision-makers.

Distributed Generation

California's *2009 Integrated Energy Policy Report* (*IEPR*) recommends expanding feed-in tariffs to help small businesses participate in the provision of resources supporting the utilities' renewable portfolio standard requirements that are close to load, including geographically specific feed-in tariffs that take into account transmission availability.[26] According to the *IEPR*, feed-in tariffs could provide publicly available, technology-specific price signals.

A further refinement of this approach would be a locational feed-in tariff that specifies for each location the characteristics of a beneficial DER project and offers a share of the project's objectively demonstrated network benefits with the third-party project sponsor. So for example, a distributed generation project at one of the identified locations on the Mussel circuit having the specified attributes could receive a tariff bonus representing a share of the total value in Section 3.3.12 for all 2011 Hobby distributed generation projects and the additional value in Section 3.3.12 for a DER project on the Mussel circuit.

To yield the posited grid benefits, each project would need to reflect the size and the operating profile specified for the Optimal DER Portfolio project at that particular location. In the SVP study, the researchers illustrated the locational differences in the characteristics of distributed generation having grid benefits. On one circuit (one street actually), there were seven customer sites. Distributed generation at four of the sites would yield grid benefits, but of varying amounts and with different specified operating profiles. Distributed generation at the other three sites did not have any specific value. [27] Within these constraints, whether a project is on the customer side or the network operator side of the meter is not relevant at least in terms of network benefits.

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26. California Energy Commission. December 2009. 2009 Integrated Energy Policy Report, Final Committee Report, CEC-100-2009-003-CTF. Available at <http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CTF.pdf>

27. Evans, P. March 2005. *Optimal Portfolio Methodology for Assessing Distributed Energy Resources for the Energynet*; CEC-500-2005-096, page 133. Available at <http://www.energy.ca.gov/2005publications/CEC-500-2005-096/CEC-500-2005-096.pdf>

Distributed generation projects having grid benefits such as those identified in the 2005 and 2011 Optimal DER Portfolios are, under the rubric of this project, a) at customer sites, and b) generally non-exporting. More precisely, under the parameters established in Section 2.2.6, Optimal DER Portfolio DG projects are sized at less than 100% of the load at the project site, and the total of all such projects on a distribution feeder is limited to well under the total load of the feeder. These limits are explicitly intended to define a population of beneficial potential DG projects while incorporating prudent operational constraints on their penetration (i.e., to ensure non-export and to avoid introducing new fault protection and anti-islanding concerns given the absence specific facilities for unsupervised breaker reclosing and resynchronization) without the need for detailed project-specific study and protection analysis.

Accordingly, a location-based tariff could promote non-exporting projects at *specific* customer sites where such projects are eligible for simplified interconnection and reflect location-specific size and operating requirements. Such a tariff could encompasses either customer-sponsored or network operator-sponsored ownership and development structures and would be priced based on the monetization of objectively determined benefits as demonstrated here. Such a tariff would capture the value associated with ideal distributed generation demonstrated in this project.

In California (in areas served by utilities regulated by the California Public Utilities Commission, or CPUC), network operators and their customers operate under several business models designed to capture the benefits of (or incent) certain types of power generation. For customer-sponsored projects, the Small Generation Incentive Program and the California Solar Initiative Program pay direct subsidies for projects employing certain renewable technologies. Project sizes are specified indirectly through a 1,500 kW programmatic project size cap and a net metering tariff that provides no compensation for any net exported energy. Project operating profiles are not specified, though only certain technologies (with their characteristic operating profiles) are eligible. The incentives are not location-specific.

Customer-sponsored projects may also sell their output (or their net output) directly to utilities at a market-based energy price with no explicit incentives; however, a limited number of projects under 1,500 kW employing certain renewable technologies can participate under a standard “feed-in tariff” incorporating a predetermined “market price referent,” eliminating price uncertainty and avoiding the cost of negotiating a contract. Projects over 1,500 kW employing technologies that qualify for California’s Renewables Portfolio Standard (RPS) receive a price established for those resources. However, other than the program specifications, there is specification or eligibility guidance with respect to project location, size, or operating profile.

SCE, as a network operator, has received approval to sponsor the development of a fixed amount of distributed photovoltaic generation on existing commercial rooftops within their service territory, with expected project sizes in the 1,000 to 2,000 kW range. Pacific Gas and Electric Company and San Diego Gas & Electric Company have submitted applications to the CPUC for similar programs. These projects will include utility-owned projects and third party-owned projects with the output sold to SCE through a price-competitive process.

For the third-party owned projects, SCE will provide some location guidance. The CPUC decision directs SCE to "identify locations where distributed solar PV will be desirable, thereby optimizing the locational value of the project sites."[28]

A utility using the Energynet® model and the methods demonstrated in this project could provide this guidance. The following discussion illustrates how this method could support deployment of such 1,000-2,000 kW commercial-scale PV projects in the Hobby system by systematically and comprehensively identifying potential sites for projects that make the best use of, or enhance the performance of, existing SCE transmission and distribution assets and have suitable host customers. This illustration also shows in part how an Energynet® model can provide tools to assess strategies coordinating all of the distributed energy resources and changeable topology in the subject system.

The researchers did not perform any analysis to directly examine the system impacts of individual commercial scale PV projects on their circuits or on the system overall, though that would be a straightforward matter.

Among the approximately 45,000 Hobby customer sites are 428 medium and large commercial and industrial sites with peak loads by the researchers' estimate over 200 kW on 144 circuits. One may consider this a generous initial set of potential sites in the Hobby area for 1,000-2,000 kW commercial-scale PV projects.

Researchers found that 308 of the 428 total medium and large commercial and industrial customer sites are also sites for beneficial distributed generation projects within the 2005 Optimal DER Portfolio; these 308 sites lie on 131 of the 215 Hobby circuits.

Among these 131 circuits, the researchers found 51 that carry individual large commercial or industrial customer sites, groups of such sites totaling 1,000 kW or more of peak customer load. These circuits and sites may represent relatively more attractive locations for 1,000-2,000 kW commercial-scale PV projects, as there is some level of load concentration. With this peak-period load concentration, it is reasonable, even without the benefit of system detailed studies, to expect the output of 1,000-2,000 kW commercial-scale PV projects to be largely absorbed locally.

This list of candidate sites may be further refined by incorporating reliability impacts using the approach described in Section 3.2.6. Of the 51 circuits with large commercial and industrial load concentrations, 17 are ineligible to accept post-contingency load shifts due to their loading. Incremental capacity on these circuits, particularly in 1,000 – 2,000 kW increments, would expand the post-contingency load shift opportunities of their sibling circuits, providing a quantifiable reliability benefit. Nine of these 51 circuits are served from substations that bear some risk of unserved load in the event of a loss-of-bank contingency. Incremental capacity within those circuits will reduce the load at risk, yielding a quantifiable reliability benefit.

28. Southern California Edison, Advice 2364-E (U 338-E), July 20, 2009.

Among this group of potential sites, there are some interesting individual examples. On Rich circuit out of Jazz 12 kV substation, there are two candidate sites whose peak load totals 1.46 MW. The researchers' analysis shows that incremental large-scale PV generation at these sites would provide voltage improvement and loss reduction to the system overall. Large-scale PV capacity at these sites would also relieve loading on elements of this circuit that the researchers found loaded to where reliability could be affected. This incremental capacity would also relieve loading on the Jazz substation transformers to permit continued operation under a loss-of-bank contingency. Additional PV generation capacity on Rich circuit could also enhance the ability of Rich circuit to accept post-contingency load transfers from two other circuits the researchers determined had meaningfully limited transfer opportunities.

In other words, PV projects in the 1,000-2,000 kW size range at either of these two sites would yield singular, demonstrable benefits. These benefits include systemwide voltage improvement and loss reduction. They also include reliability benefits associated with a reduction of critical circuit element loading, reduced risk of unserved load following a transformer outage, and an expanded ability to accept post-contingency load shifts from neighboring circuits that are otherwise compromised. One of the two Rich circuit sites also has significant flat roof space and a southwest orientation, suggesting a good large-scale rooftop PV site.

Two other candidate sites, on Oak circuit out of Tree 12 kV substation, have peak loads totaling 1.244 MW. The researchers' analysis shows that incremental large-scale PV generation at these sites would have the same types of grid benefits as generation at the two sites on Rich circuit – voltage and loss benefits, relief for overloaded elements, continued operation under a loss of substation bank contingency, and opening up post-contingency load transfer opportunities for one circuit with limited transfer opportunities.

Large-scale distributed generation projects at these four locations would yield grid benefits; the value of those benefits based on the benefit categories described above could either be directly or objectively calculated. Because these are also sites with large peak-period load concentrations, the interconnection of these projects should have minimal grid impacts. This illustration also shows the precision with which these high-value locations must be defined. In the SVP project final report the researchers showed one circuit (one street actually) with seven customer sites. DG at four of the sites would yield grid benefits, but of varying amounts and under different operating conditions. DG at the other three sites did not have any specific value. Likewise, in the example above the researchers identify four individual street addresses within the 1,000 square mile Hobby system that are particularly attractive sites for large-scale PV development.

Demand Response

The benefit categories to which demand response contributes value suggest a more evolved implementation of demand response as a resource. Demand response provides incremental bulk system capacity, and when called, incremental energy. Demand response also provides some congestion relief, loss reduction, and emission reduction benefit when called. In addition, demand response can provide ancillary services capacity (spinning reserves) and system voltage security value if dispatch is responsive enough and quantities are large enough.

Demand response in specific locations can provide load relief and reliability benefits provided those resources can be called by the system operator by individual location or at least on a circuit-specific basis.

Fortunately, the work performed by CERTS suggests that most or all of these benefits can be obtained under the present demand response business model of California's utilities, and even using the present demand response technologies. The CERTS study demonstrates circuit-level dispatch and demand response performance for spinning reserves with existing controls and monitoring, as well as the ability to use demand response repeatedly in spinning reserve service without customer complaints. It also shows successful demand response marketing efforts to obtain high concentrations of demand response on a particular circuit.

3.4. Network Monitoring

3.4.1. Augmenting Current, Power Factor, and Voltage Instrumentation

As presently deployed within the Hobby system, Schneider Electric Lab reclosers monitor current, demand, and voltage, Cooper 451 reclosers monitor current, and S&C Intellicap capacitor controllers monitor voltage. SCE operates a UtiliNet packet radio system employing DNP3.0 communication protocol to deliver readings from these devices to an archive system managed with InStep Software's eDNA data historian package.

In addition to this distribution system instrumentation, SCE operates SCADA systems at many of the substations in the Hobby system. Most SCADA-equipped substations have voltage monitoring on the operating bus serving the individual circuits, as well as current for each of the three phases and MVAR reads for each circuit.

The data from the SCADA system are also handled through eDNA. Operationally the substation SCADA and distribution device monitoring systems are integrated – for some circuits served from substations without SCADA systems, circuit current and MVAR data taken from distribution devices such as reclosers are presented alongside circuit current and MVAR data from the SCADA system.

The distribution instrumentation includes reads other than current and voltage. Capacitor controllers provide information on device status (ON or OFF), and in some cases the number of operational cycles. Some reclosers provide data on harmonic distortion and local temperature.

The researchers were able to obtain circuit voltage measurements from most of SCE's automated capacitors and those reclosers with voltage measurement. The researchers were also able to obtain circuit current measurements from the SEL and Cooper reclosers as well as from substation SCADA, where available. These along with the substation bus voltage and circuit current and MVAR reads from the SCADA system constitute the majority of the monitoring points used in this project. The researchers were also able to obtain device status data from the automated line capacitors. The researchers did not have device status data for the Hobby system's substation capacitors, though those data may have been maintained in SCE's data system.

Altogether, the researchers identified and had access to over 4,500 individual data points from existing system monitoring within the Hobby system.

The researchers were able to map essentially all of the distribution device monitoring and SCADA points to individual buses or nodes within the Energynet® model topology. This was a relatively challenging integration as the databases for the instrumentation and the databases for the system data are maintained separately. Further, once established, this datapoint mapping was exposed to the constant change within the distribution system as these devices are placed in service, removed from service, and relocated in normal day-to-day operations.

The researchers found the integration of this extensive existing instrumentation with the system topology to be an important outcome by itself. Placing individual device data into the system topology gives it more relevance. To illustrate, Figure 24 shows the voltage profiles of five circuits served from a substation. The data in Figure 24 are all taken from previously existing instruments in SCE's data system. However, due to the mapping of these datapoints to the Energynet® model topology, the researchers are able to present these data: a) as related to circuits of a particular substation, b) as related to each individual circuit, and c) within each circuit, as related to points having different distances in line segments from the substation. This reveals information about the substation transformer tap setting as it influences the voltages of the circuits at the getaways—in this case, the voltage is slightly elevated relative to 120 volts nominal. It reveals information about the voltage drop on each circuit—Circuit 04723 has the greatest drop among this group. It reveals information about the impact of circuit length—Circuit 18229 is much shorter than the others are, though the longer ones maintain strong voltage throughout. It reveals information about the function of individual devices—the device at the end of Circuit 12526 is contributing to relatively high voltage under this set of conditions. This additional perspective comes solely from the placement of existing data onto individual points within the topology of a high-definition system model.

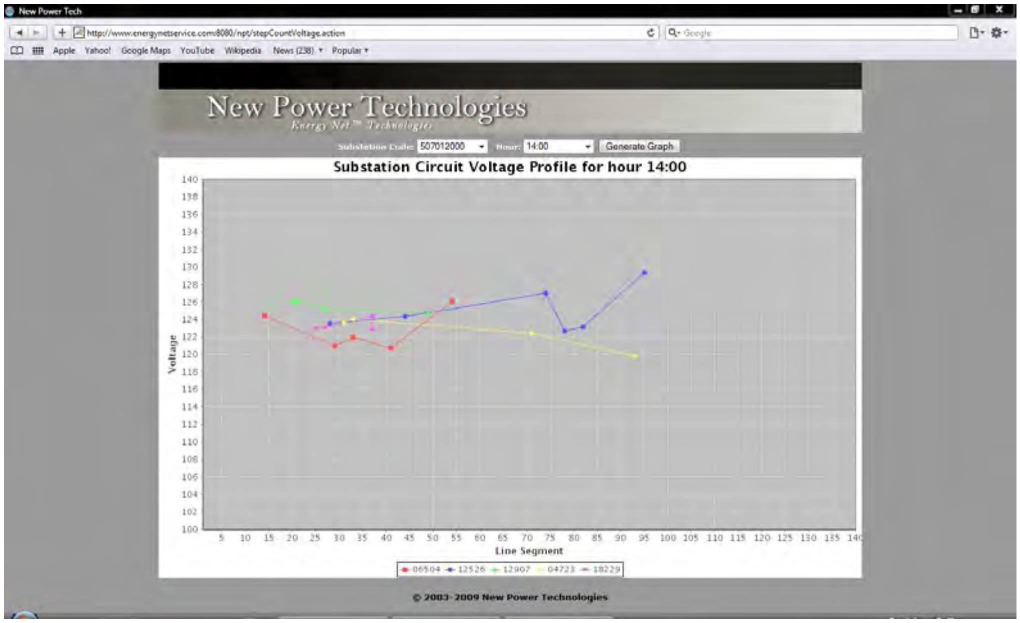

Figure 24. Circuit voltage profiles from existing datapoints

Having placed the existing instrumentation into the system model, the researchers conducted a study using the Energynet® model to look across the Hobby system and identify gaps, or those locations where the project's basic functional specification for monitoring density was not met. The researchers identified approximately 50 circuits lacking current and power factor data and approximately 60 locations where an additional voltage read would describe a voltage profile for the circuit.

For augmenting current and voltage reads, the researchers selected GridSense LT40 LineTrackers. These devices comprise a line-hung sensor for each phase and a data collection and transmission box, or DataPAC mounted on a nearby pole (see Figure 25 and Figure 26).

The individual LineTrackers are mounted on the conductors using a hot stick. The LineTrackers communicate wirelessly with their DataPAC and are solar-powered. The DataPAC includes the communication package and may be powered with instrument power if available or with solar power. The LineTracker and DataPAC set is commissioned from the ground with a handheld device. With these features, the Line Trackers can be easily installed with a minimum of fieldwork. A potential further benefit of the LineTrackers was the ability to enable a triggered event-capture feature that provides storage of high-resolution reads and current wave forms following trip of a specific trigger. This would provide detailed distribution-level measurements to support studies such as HVAC stalling. SCE also had previous experience with the LineTrackers.

Figure 25. GridSense LineTracker (A)

Photo Credit: GridSense, Inc.

Figure 26. GridSense LineTracker (B)

Photo Credit: GridSense, Inc.

The base LineTracker unit was not initially offered with the capability to measure power factor. As part of the purchase for this project, GridSense implemented a firmware upgrade to the LineTracker units to support reading of power factor and power angle.

In February 2009 SCE provided sample reads from one of the early LineTrackers and enhanced with power factor and UtiliNet/DNP3.0 capability (discussed below) mounted outside a SCADA-equipped substation. The reads compared the data via SCE's data system with local reads, verifying the function of the communications and data system, and with reads from the substation, verifying the function of the instrument itself, including the phase angle and power factor feature. Figure 27 shows the high phase current and total angle reads of the LineTracker, read via the communication system, compared with same reads from the substation SCADA, in three instances – with a local capacitor off, turned on, then off again.

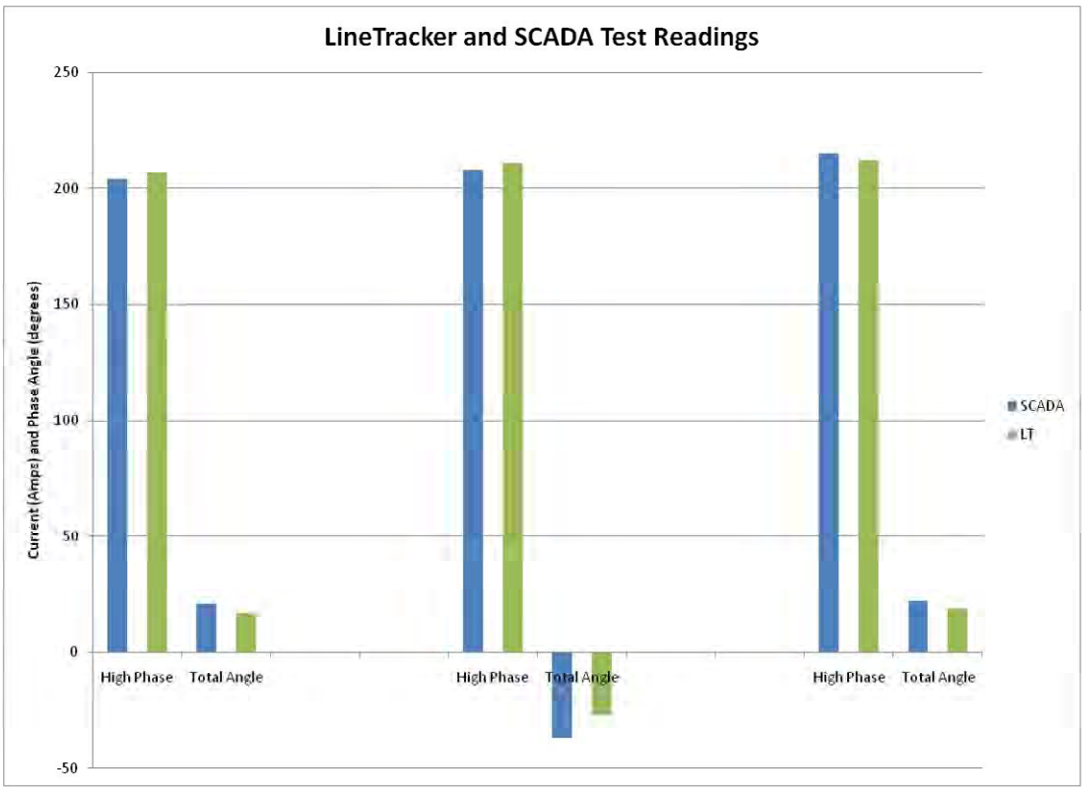

Figure 27. LineTracker and SCADA test readings

Power to serve system instrumentation is highlighted by EnerNex as a key issue for smart grid monitoring.[29] GridSense addresses this with the use of solar power and batteries for both the

29. EnerNex Corporation. March 2008. *Retrofitting Legacy Distribution Automation Equipment to Facilitate Accelerating the Deployment of Smart Grid Applications.* PIER Interim Project Report.

LineTracker devices and the DataPACs. SCE's desire was to use alternating current (AC) power for the DataPACs where available. Of 46 LineTracker monitoring sites, 24 did not have AC power available and were implemented with only the solar power option.

Augmenting voltage monitoring sites were established for this project using SCE's standard commercial and industrial (C&I) customer meters, which incorporate voltage reads as well as UtiliNet/DNP3.0 communication. The voltage monitoring sites required pole mounting of a meter socket and conduit on the pole to PTs on the three conductors.

SCE encountered an expected level of difficulty finding suitable voltage monitoring sites. Sites that were desirable in terms of topology were sometimes inaccessible or in locations where traffic made them difficult to work at. In areas that are largely underground, SCE had to find structures like street lights that are overhead and have available AC power. A particularly difficult area to monitor was a gated community with underground service and customer-owned street lights. Because the voltage monitoring sites are useful within a range of locations (e.g. "near" the substation or "far" out on the circuit), it became evident that assessing every possible site would be time-consuming. The researchers used the Energynet® model to identify for SCE a set of individual candidate locations that the researchers screened based on a set of criteria SCE provided. These were initially overhead structures within the right range of locations serving customer transformers. Ultimately, most of the voltage meters were installed at Netcom Monitor sites.

3.4.2. Remote Reading and Data System Integration

As stated above, SCE's legacy distribution monitoring system uses a Utilinet packet radio system employing the DNP3.0 communication protocol to deliver readings from its distribution system monitoring devices. DNP3.0 is a common communication protocol found among legacy and new system monitoring equipment. According to EnerNex, Utilinet is a common though proprietary mesh radio system used by many utilities.

At the point when the researchers committed to the GridSense LineTrackers for current and power factor instrumentation, GridSense did not support UtiliNet and DNP3.0 communications. So the LineTracker DataPACs for this project were originally specified with GSM/GPRS cellular modems, and the researchers planned to establish a cell phone account for each of the LineTracker sites.

GridSense would also supply its G-Server software for automated remote LineTracker data retrieval. The researchers anticipated establishing a server on site at SCE to host the G-Server system and developing and implementing a databridge to link the G-Server database with SCE's data management system.

GridSense and SCE had discussed developing UtiliNet/DNP3.0 communications capability for the LineTrackers as a technology development activity within the Advanced Grid Application Consortium (GridApp), and in the first half of 2008 GridSense delivered a prototype to SCE. In mid-2008, in consultation with SCE, the researchers agreed to commit this project augmenting instrumentation, including the LineTrackers, entirely to SCE's legacy UtiliNet/DNP3.0

communication path. This decision was based on SCE's early testing of the GridSense UtiliNet/DNP3.0-enabled DataPAC.

This adaptation proved successful, with the LineTrackers functioning within SCE's distribution monitoring system alongside equipment provided by several other vendors. This reinforces the contention that broadly accepted communication systems, even if proprietary, can support integration of new equipment with legacy equipment in a distribution monitoring system and provide some vendor independence for utilities.

In terms of data management, SCE collects the data from its distribution system instrumentation along with reads from the substation SCADA devices to an archive system managed with InStep Software's eDNA data historian package. Within the eDNA rubric each LineTracker set and DataPAC represents nine "datapoints" – current, power factor, and power angle for each phase. SCE personnel assigned IDs to these datapoints and they were seamlessly incorporated into eDNA.

With the successful adaptation of the UtiliNet/DNP3.0 communications and successful integration of the LineTrackers as datapoints within eDNA, it was possible to collect data from both the legacy instrumentation and the augmenting instrumentation through one portal, the eDNA system.

Figure 28 shows a set of LineTracker 3-phase current reads in eDNA on a circuit of the Hobby that had no pre-existing current instrumentation. This demonstrates the full integration of the LineTracker devices in SCE's communication and data systems, directly readable alongside SCE's legacy SCADA and distribution monitoring.

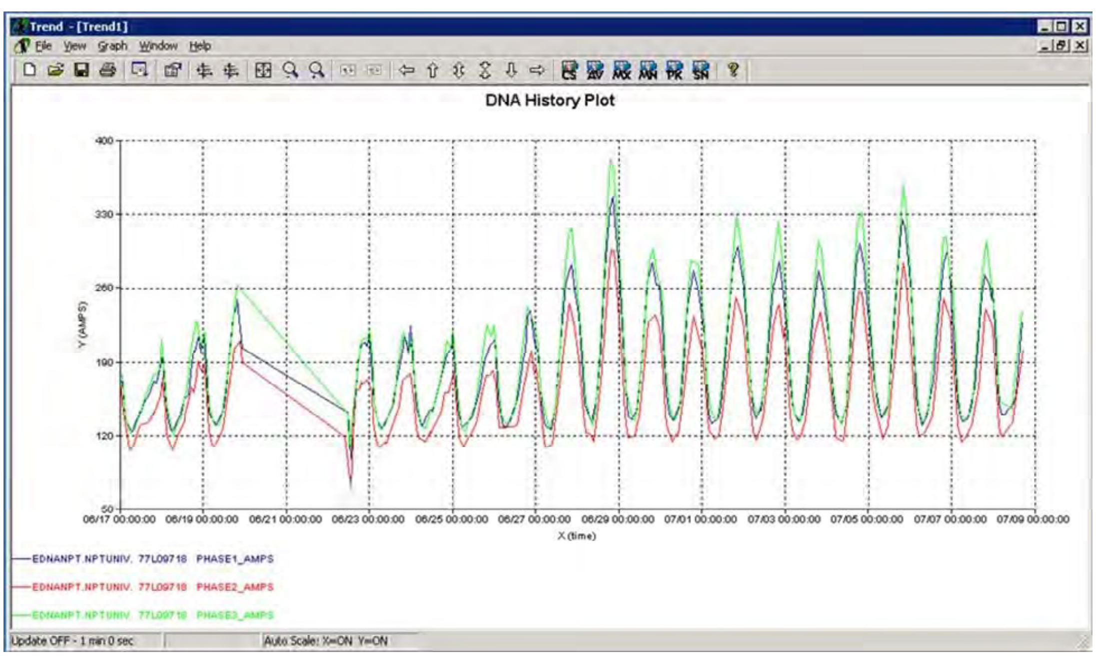

Figure 28. LineTracker current reads in eDNA

3.4.3. Wide Area Monitoring

The field monitoring effort for this project originated nominally to provide data against which to validate the Energynet® system simulation. However with this project's augmentation of the Hobby system's legacy instrumentation, the implementation of the eDNA data bridge, and the mapping of the system instrumentation to the Energynet® system model's topology, the result was a power network monitoring system spanning a wide area (i.e., served at the transmission level with hundreds of distribution circuits) but reaching into individual distribution circuits and below having all of the following characteristics:

- Uniform, nominally gap-free monitoring density
- Topological visualization of sensor data
- Continuous direct system sensor measurement
- Data delivery to a central location
- State estimation (through the Energynet® simulation model) for monitored and un-monitored locations and devices

This monitoring system has many, though not all, of the features of wide area monitoring systems (WAMS) proposed to support smart grid applications. According to the Smart Grid Interoperability Standards Roadmap, a wide area monitoring system must capable of supporting applications requiring an understanding of the state of individual power system components across the system and how they affect the entire system, referred to as wide area situational awareness (WASA) applications.[30]

In this project the researchers accomplished this largely through the integration of existing monitoring, data collection, and data management systems with a system model having sufficient detail to characterize each distribution monitoring point and the system nodes in between. The scale of this deployment is significant. Table 95 provides a comparison of the Hobby monitoring network within the context of two other well-publicized "smart grid" demonstrations. The key observation is that the scale of the Hobby system is 5-10 times the size of the "Smart Grid City" project. At the same time, the Hobby monitoring system was operational in 2009 and at minimal cost when compared to the other examples in Table 95 even with the difference in automated metering infrastructure (AMI) is taken into account.

The Hobby monitoring system is distinguished by its intensive use of legacy equipment; the researchers achieved a uniform monitoring density and pervasive monitoring by adding to the stock of monitoring devices in the Hobby system by less than 10%. The project demonstrated the seamless integration of the added monitoring devices, both the collection of their data remotely and the handling of their data once collected, within the legacy systems without modification. The researchers found that the largest challenges were local – finding sites for instruments and providing instrument power.

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30. Electric Power Research Institute. June 2008. *Report to NIST on the Smart Grid Interoperability Standards Roadmap.* Contract No. SB1341-09-CN031.

Beyond providing data to support validation of the Energynet® model, this monitoring system is a clear demonstration of the practicality of pervasive system monitoring achieved through legacy assets and detailed power system models.

Table 95. Comparison of "Smart Grid" demonstrations

	Xcel "Smart Grid City"	CEC "Hobby"	Progress Energy Carolinas
Customers	50,000	280,000	
Substations	5	54	
Circuits	27	240	
Element-level system model	no	Energynet®	?
Integration with legacy IT, OMS	Accenture	Energynet®	Telvent
Pervasive, real-time system monitoring	CURRENT Group	SCE DCMS*, EMS*, LineTrackers	Telvent DMS
Power flow analysis		yes	yes
Volt-VAR management	yes	yes	yes
Loss reduction	no	yes	yes
Distribution Automation	Schweitzer Engineering Labs	SCE DCMS*	Telvent DMS
DG Integration	yes	yes	
DR as a "virtual resource"	yes	yes	yes
Data management/historian	OSIsoft PI	InStep eDNA	
AMI	included	coming	
	2010	Operational 2009	2011
Cost	$100 million	$2 million	$250 million

* Hobby demonstration makes extensive use of SCE's legacy distribution instrumentation and control

Source: New Power Technologies Analysis from media reports

3.4.4. Survey of Alternate Instrumentation Approaches

As stated above, for this project the researchers sought system condition monitoring to provide distribution line measurements to augment existing distribution monitoring sites using devices that ideally would have the following characteristics:

- Current and power factor reads.
- Easily installable by field personnel (e.g. temporary clamp-on instrumentation).
- Does not require field installation of secondary voltage power supply.
- Remote data collection (rather than field collection) that can be integrated with the existing distribution monitoring data systems.

As of early 2009, distribution line condition monitoring approaches seem to lie in two domains:

a) Monitoring embedded in distribution devices having other primary functions, such as switches, reclosers, and capacitors
b) Standalone monitoring devices.

Many equipment vendors provide, as packaged with switch, recloser, and capacitor controls, sophisticated power quality monitoring capability (current, voltage, power factor, harmonics, etc.) along with two-way communication using one or more standard wireless and wired communication paths such as UtiliNet/DNP3.0, WiMax, GPRS or other cellular telephone communication, or Ethernet. S&C Electric (IntelliTEAM), SEL, Cooper, Schneider Electric/SquareD, and Siemens all offer devices with these attributes.

Thus, the network operator, SCE in this case, may readily purchase switches or capacitors that will incorporate field-monitoring points that can interoperate with SCE's existing communication and data management infrastructure. As discussed above, this also may mean that there are many existing monitoring sites within a given system.

However, these devices are expensive. Their use must be justified by the underlying device rather than just the opportunity to establish a new monitoring point. SCE may install automated capacitors where needed for their reactive power capacity as a matter of policy, or may install an automated switch to provide a specific functionality, but in neither case will do so solely to establish a monitoring point. In the case of the Hobby system, it is the presence of large numbers of such devices makes pervasive monitoring even a possibility. However, they are not a practical choice for purely augmenting monitoring to achieve a desired monitoring density.

The offerings of these manufacturers probably represent the most mature implementations of communicating distribution system sensors. Interestingly, S&C, SEL, Cooper, Schneider Electric and Siemens all indicated that they do not offer off-the-shelf standalone line condition monitoring solutions that incorporate power factor. In addition, use of just the sensing and communication components from these manufacturers as adapted monitoring would require hard-wired installation.

Standalone monitoring devices seem to fall into a different class. These are sensors installed apart from switches, capacitors, and substations solely for monitoring purposes. Ideally such sensors are relatively inexpensive to purchase, easy and flexible to install, but still provide the appropriate scope and accuracy of measurement, as well as communication capability.

Fault indicators arguably fall into this category, as they are inexpensive and easily installed by simply hanging on the conductor. However, they often do not provide operating current – and nearly always do not provide power factor or voltage measurements – needed for non-fault condition measurement. They have only recently begun to incorporate communication capability. Deployment of overhead fault indicators with communications capabilities in the GridApp Consortium was named one of 2009's Projects of the Year by *Utility Automation & Engineering T&D Magazine* at DistribuTECH 2009.

GridSense, Inc. (www.gridsense.com) and PowerSense A/S (www.sensethepower.com) offer a related class of devices. These devices hang on the conductor like a fault indicator, but they offer a more complete suite of non-fault measurements and they also incorporate communications. The PowerSense DISCOS optical sensor solution measures current, power factor, direction, and voltage, operates on instrument AC power or solar power, and supports the DNP3.0 protocol. The PowerSense sensor is wired to the data collection and communication box. The GridSense LineTracker as used in this project measures current and power factor and supports DNP3.0 protocol over UtiliNet radio. The LineTracker also supports some logging functions. The LineTracker communicates wirelessly with a pole-mounted data collection and communication box. The LineTracker DataPAC communication box can run on instrument power or a photovoltaic cell with a battery.

These sensors are easily installed and easily redeployed, and that represents their main appeal. A major limitation of both of these devices is that they cannot be used on underground lines.

A slightly different variant of this approach is offered by Lindsey Manufacturing, Inc. (www.lindsey-usa.com). In this case, the sensor is embedded in the insulator rather than hung on the line. This is much more involved installation requiring a new pole top crossbar, though some variants of the Lindsey sensor can be installed around conductors so they do not have to be cut. The Lindsey sensor referred to as a Current and Voltage Monitoring Insulator (CVMI) measures current and voltage but evidently does not measure power factor. The Lindsey sensor includes a variant for measuring voltage only. Lindsey also offers Elbow Sense Current and Voltage Monitors for underground applications. The Lindsey sensor is used with data collection and communication capabilities of others and is offered through several major power system vendors.

The PQube AC Power Monitor offered by Power Standards Labs (www.powerstandards.com) represents a class of compact, low-cost packaged condition monitoring instruments. The PQube measures real and reactive power, voltage, and includes logs on an onboard Secure Digital-card. The PQube is offered for distributed generation monitoring applications and could possibly be adapted to distribution system-level voltages and outdoor applications. It would have to be hard-wired and would require external communications.

Another approach to standalone monitoring solutions to support pervasive system monitoring is the use of a “smart” customer meter as a system monitoring point. C&I meters of several vendors include measurement of current, power factor, and voltage, and some support a variety of communication protocols including DNP3.0. They are relatively inexpensive but require the field installation of potential transformers and current transformers, conduit, and a box or socket on the pole. This is the approach the researchers ended up with using for voltage monitoring sites for this project.

The researchers’ conclusion is that the market for distribution monitoring devices specifically for augmenting existing monitoring and/or to infill to achieve a consistent ”monitoring density” is nascent. With the addition of power factor measurement and DNP3.0 over UtiliNet, the ease of installation and integration of the LineTracker made it a good fit for this study at the time the researchers needed to make a decision. There are several established manufacturers with products that could migrate to this application.

3.5. Operational Applications

The researchers' experience in developing and updating the various system simulation models for this project showed that the underlying system data are very dynamic. The researchers saw meaningful changes in system layout from week to week. This suggests that to support operational applications any Energynet® model would have to be updated very frequently.

The successful demonstration of relatively rapid updates of the Energynet® system model introduced the possibility that the Energynet® method could support operational decision-making even in light of frequent system changes. As noted in Section 3.1.1, SCE representatives promoted this possibility.

Accordingly, one of the elements incorporated in the field demonstration plan was a goal to explore the practicality of conducting even more frequent updates of the Energynet® simulation model, to obtain simulated conditions of the subject system within the week or day. The plan contemplated implementation of data transfer infrastructure to reduce the human steps otherwise needed to gather and deliver data to update and populate the system model.

As indicated here, the researchers committed to an entirely Web-based infrastructure for both the receipt of data from SCE and the management of data within the Energynet® model, using secure Web services to move data between its sources and where it would be used. The researchers believed this would provide greater security, reliability, and scalability than a local site, even one at SCE, and would support data update streams of any frequency.

The researchers reviewed the security capabilities of several top tier Web hosting providers, as well as the researchers' own internal practices within the project team, and met with SCE via teleconference to review the methods for protecting data in transit between servers over the Web and resident on hosted servers. There was a set of elements acceptable to SCE that the researchers implemented, noting that both SCE and New Power Technologies might be subject to regulatory audits to ensure use of appropriate practices.

The researchers established hosted servers to support system data, system condition data, Energynet® data processing software, and end-user functionality as it developed. Working with InStep, the vendor for SCE's data management system, the researchers established a remote server implementation of their eDNA software that would connect with the implementation at SCE to move data from SCE's SCADA and distribution monitoring systems. This eDNA to eDNA data bridge, once established, is continuous.

The data system supporting SCE's power system data has fewer features for this type of data exchange. However, SCE was able to establish a script to produce the needed system data and send it to the researchers' servers via secure Web link, all on a partially automated batch basis on request. The researchers completed at least five data transfers over this data bridge.

Conceivably this transfer mechanism could be further refined into a daily, fully automated process.

Each system date's data is processed by the Energynet® software directly from the server upon which it resides. The user specifies a "load date" for which data on system device status, loads, and system condition data from the eDNA archive are obtained and incorporated into the model. The "*.epc" files are then posted to a password-protected site from which they can be downloaded and imported into PSLF.

Part of this implementation was a systematic method for managing islands in the model; one method the researchers hoped to use as a check was a determination that there were no new islands in a new set of system data. The researchers found that new islands are in fact a regular occurrence with each new set of data. The processing revealed with the first few datasets that they were incomplete. Later, in comparing datasets known to be complete, the researchers found that there are always a few new islands. The accuracy of the model demands that these be identified, though they are nearly always inconsequential from a power flow standpoint. It takes a human to decide whether to correct them or maintain and track them. The Energynet® software has sophisticated tools that characterize any island and show how to resolve it, so this is not a time-consuming process. The net result is that a daily model update is possible, but generally requires human intervention at least one point.

With this infrastructure in place, the researchers successfully process system-data batches as closely spaced as two days, in each case performing the update in as little as one day, suggesting that a daily update of the system is feasible.

3.6. Verification of Methodology

One of the core research goals of this project was to validate the methodology's characterization of the subject system as an integrated network with field measurements. The results presented here[31] fully meet that goal.

Inherent in the researchers' approach to developing the Energynet® simulations is a substantial amount of manipulation of source data, with embedded infill assumptions, interpolations, and extrapolations. Much of this manipulation is context-sensitive. This manipulation keeps the source data quantity and quality requirements reasonable. Further, it is the researchers' view that one of the benefits of this approach is to identify that small fraction of data in the total set that, if correct, might drive particular decision. Verification of these key data would be a more reasonable task.

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31. Evans, P.B., Lind, S., Dossey, T. *Validation of High-Definition Electric Power Delivery Network Simulation*. IEEE Power and Energy Society General Meeting, 2010. PESGM 2010. IEEE, August 25-29 2010, PESGM2010-001582. Portions used here pursuant to the Commission's reserved rights.

While manufacturing datasets in this way has appeal in terms of practicality, the risk is that the cumulative impact of this data manipulation causes the simulations to stray so far from reality that they are not usefully predictive. In particular, the Hobby Energynet® model does not incorporate customer-specific real or reactive load data and incorporates a meaningful amount of infill of line specifications. If "real" load distributions, power factors, or line impedances are vastly different from those incorporated in the model, simulated power flows and voltages will not align with those read from field instruments under like conditions.

The researchers developed an Energynet® dataset for Hour 20 of Thursday, September 10, 2009, the 2009 Hobby "verification" model. Hour 20[32] was the peak-load hour of that day. The system was modeled as it stood that same day, reflecting system data from SCE's source data systems on that day. The model was built up based on actual loads recorded for that hour, and capacitor device status reported through the distribution monitoring system for that hour. To reiterate, the Energynet® model development approach employs algorithms to fill in missing data for load, power factor, and device status.

The process for developing the verification model is described in Section 3.1.2. The initial assessment of the as-found conditions is described in Section 3.2.

The system monitoring infrastructure described above provides a nominally gap-free, area-wide network of system monitoring points. With the researchers' specified monitoring density and the targeted citing and integration of augmenting instrumentation, essentially all of the nearly 250 feeders of the Hobby system have some condition monitoring within this infrastructure. The researchers were able to use SCE's legacy communication and data management systems to collect data from these devices and archive them for later analysis. Using the data bridges the researchers implemented to support operational applications, these data are directly available to the Energynet® simulation of the Hobby system.

In comparing simulated results with field data, the researchers considered MW flow, megaVolt-Amps (MVA) flow, and current flow in particular line segments, and voltage at particular points. The researchers had field flow reads mapped to individual line segments within the Energynet® model at approximately 214 points, all on different circuits, with the system. The researchers had field voltage reads mapped to individual system devices at approximately 650 points, also widely dispersed within the system.

Figure 29 shows a scatter of simulated megawatt (real power) flow at 174 line segments where field instrumentation provided current, MVAR flow, and voltage. Figure 29 demonstrates a very strong correlation between field values and values from the simulation at these points; the data appear sparser than they are because many points are sitting directly on top of one another.

32. The hour value for this case is a nominal value taken from the field instrumentation archives.

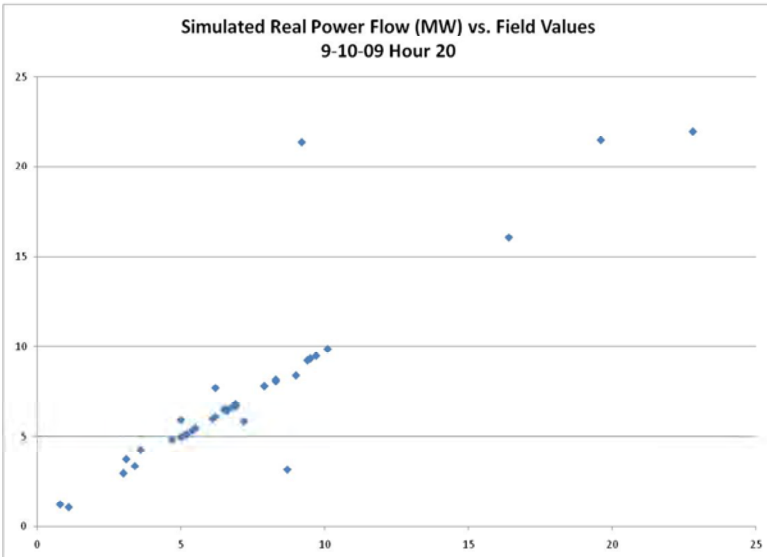

Figure 29. Real power flow comparison

The actual field reads at these locations are 3-phase current, aggregated MVAR, and voltage. The researchers found the availability of MVAR flow and voltage from field instruments to be particularly important. The availability of MVAR flow or power factor data along with current data makes it possible to calculate MW flow directly from field data and to determine the actual power factor of nearby loads for the simulation. The availability of voltage data at the location or nearby also supports the direct calculation of MVA and MW.

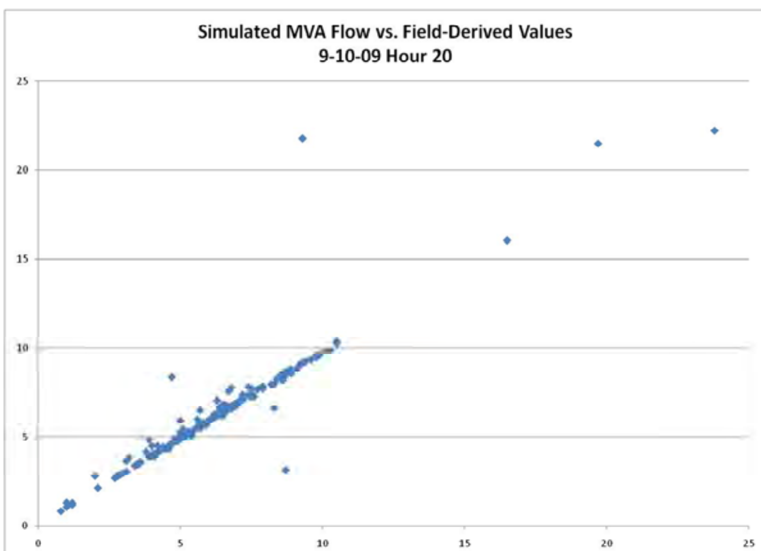

Figure 30. MVA Flow Comparison #1

Figure 30 compares MVA flow derived from field values with simulated MVA flows at those same 174 locations. Again, the field instrumentation permits the direct calculation of MVA at these line segments. The model derives MVA from MW and MVAR flows, so small differences in voltage between the field and the model at these locations can introduce differences in the MVA values. In particular, as the effectiveness of capacitors varies with the square of the voltage, even small voltage differences between simulation and field can impact MVAR flows enough to distort MVA.

Figure 31 compares simulated current flows with field measured current flows at these same 174 locations. In these locations current is measured directly, while in the simulation current is derived from MW and MVAR flow and voltage. Voltage affects MVAR flow, and voltage also affects current as it is derived from MVA flow. Thus, these current data compound the impact of small differences in voltage between the simulation and the field at these locations.

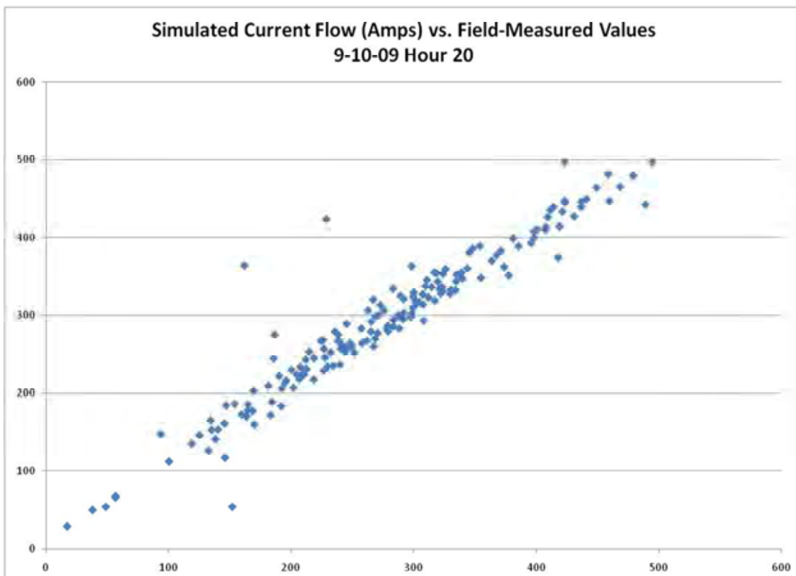

Figure 31. Current Flow Comparison #1

The availability of field voltage reads at these locations has a further benefit for the model in that the researchers are able to adjust modeled transformer taps at these locations to come closer to the field-measured voltage. As a result, these locations are among those where the voltage difference between the model and the field is smallest. Figure 32 compares simulated and field current values at seven locations without voltage reads. In each of these locations, field current is converted to MVA and modeled MW using a nominal voltage value. Importantly, this nominal voltage would probably differ meaningfully from the actual field voltage in each location if it were known. Further, without field voltage reads, the researchers are not able to adjust modeled transformer taps in these locations to align simulated voltage more closely with field voltage. Finally, simulated MW and MVAR are converted back to simulated MVA and current using simulated voltage values that may differ from field voltage values. The result is a greater scatter in the comparison of field and simulated current at these locations.

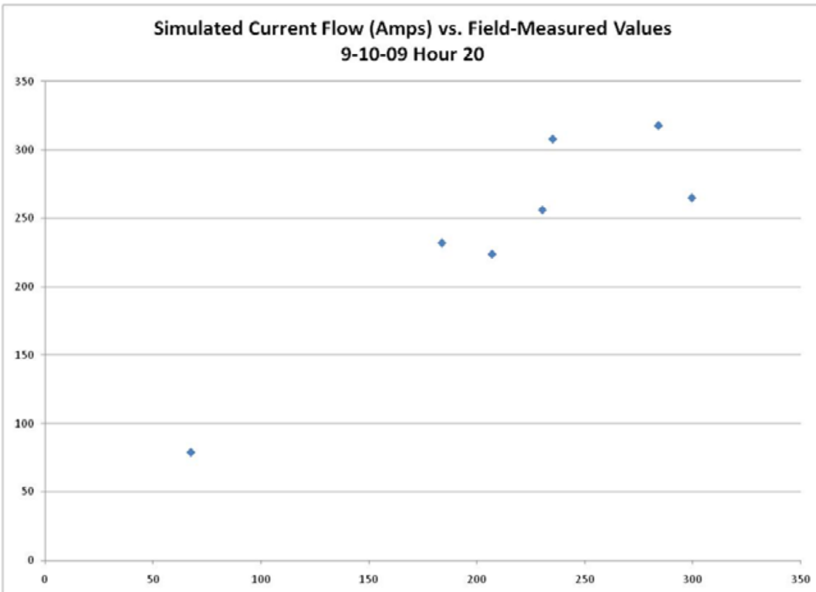

Figure 32. Current Flow Comparison #2

Figure 33 compares simulated and field-derived MVA flow at 14 line segments where current and voltage reads are available. At these locations, the lack of MVAR data prevents direct calculation of reactive loads or MW flows. However, the availability of field voltage data supports the conversion of current reads to MVA values with actual voltage rather than nominal voltage data, and permits researchers to reduce the differences between field voltage and simulated voltage at these locations through transformer tap adjustments.

Figure 34 compares simulated and field-read current values at those same 14 locations. Here, the simulated current is derived from simulated MW and MVAR flows in which the MVAR flows are based on loads with assumed rather than measured power factors. Therefore, the cumulative impact of assumptions begins to manifest itself in the somewhat greater scatter of the data.

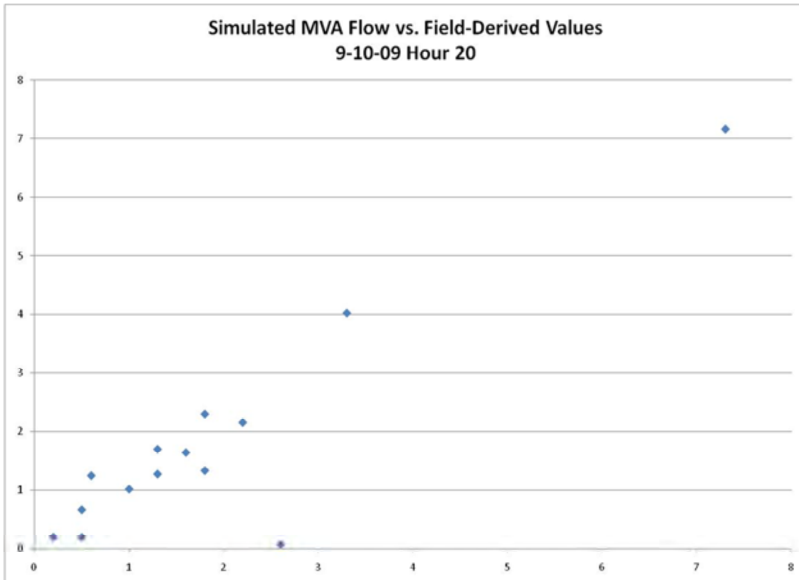

Figure 33. MVA Flow Comparison #2

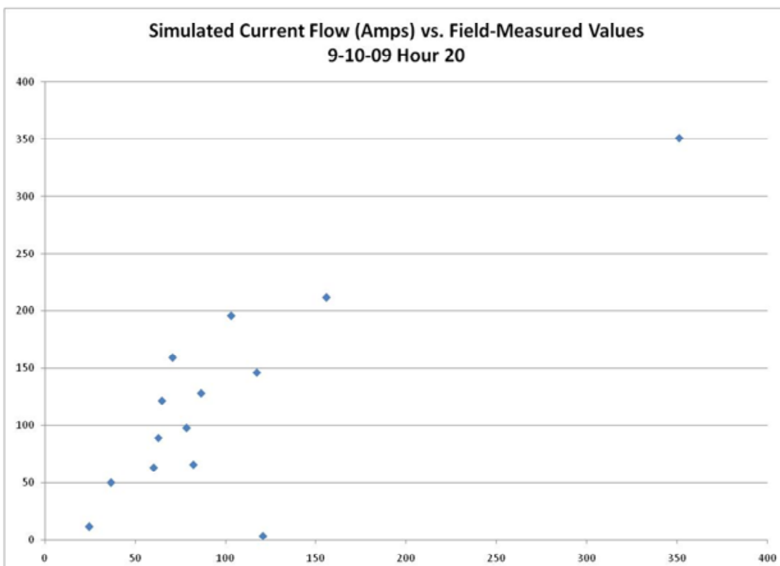

Figure 34. Current Flow Comparison #3

These graphs (other than Figure 32) all compare field-measured values or values derived entirely from co-located field measurements with values from the Energynet® simulation at these same locations. The correlations are very strong, indicating that where the model can be populated with good field data, a close representation is carried through the model to its outputs.

A *much* more demanding test of the Energynet® simulation is the comparison of simulated and field-read voltage data. This is because in this system the field monitoring points for voltage are far more dispersed than those for current, and the comparisons can be made at a wider variety of points. More importantly, as the topological point of comparison reaches further out on a distribution feeder, the simulation carries the *cumulative* effect of assumptions regarding load distribution, load power factor, line impedance, and even topology. Added to these is the cumulative effect of simulation-to-field voltage differences both in terms of their direct values and in terms of their impact on the effective reactive capacity of individual capacitors along the way.

Figure 35 compares the simulated voltage values with field-read values from approximately 650 locations and points within the model. The locations include both substation bus measurements and measurements dispersed out along distribution feeders; in fact, the feeder measurements represent the vast majority. All of the values are expressed on a per-unit basis to permit comparisons across different nominal voltage values.

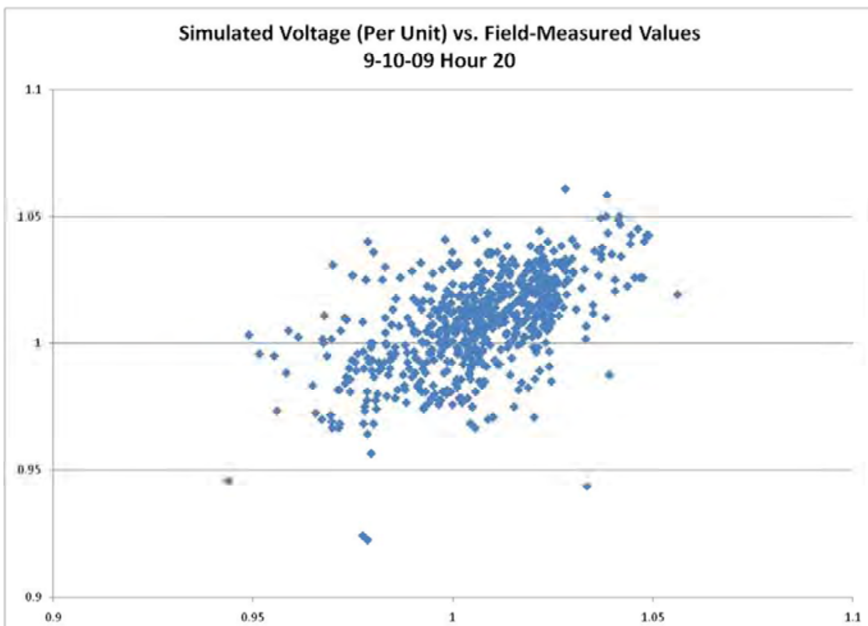

Figure 35. Voltage Comparison #1

Based on a statistical analysis of these data, the simulation model appears to be a highly statistically significant predictor of actual field voltage data at an error level of less than 0.0001 (0.01%). With a statistical sample of 649 observations, the researchers ran correlation and regression analyses and paired sample mean t-tests to determine the statistical significance of the simulation models as a useful and valid predictor of field voltage conditions.

The paired t-test shows that mean differences between the two data sets are not statistically different from zero, suggesting that simulation values and field values on average are not statistically different. The paired two-sample means t-test indicates that the hypothesized mean difference between simulator and field values is zero, where the simulated mean value (1.00686) is statistically different from the field voltage mean value (1.00842) due only to random error with a probability of $p = 0.022$ (2.2%).

Correlation and regression analyses show the simulation model to be a statistically significant predictor of field voltage values. Pearson's correlation coefficient (0.558) suggests that the simulator and field values are correlated at a moderately strong level. The regression model 's coefficient of determination ($R^2 = 0.312$) shows that the simulation values are statistically significant predictors of the field values with 32.2% of the variability in the field values explained or predicted by the simulation values. This R^2 value is a reasonably moderately strong explanatory model for field voltage values that have an overall average variability of about 2% (coefficient of variation = 0.019). Regression analysis of the simulation model as a predictor of the field voltage values is statistically significant at $p < 0.00001$, indicating that the simulation model is an accurate predictor of actual field values. The scatter plot of the field and simulated values in Figure 35 demonstrates visually this same moderately strong predictive relationship.

The researchers' conclusion is that these statistical tests suggest that the simulated values are well aligned with field values, considering that one would expect at least some variation between the two because the model is attempting to simulate field values. From these data, the researchers conclude that the simulation model, statistically, provides a valid representation of field values. [33]

Figure 36 compares the simulated and field-read voltage profiles of individual circuits of Fish substation.

33. The statistical analysis methodology used here was suggested by Samuel L Lind, Ph.D., Associate Professor, School of Economics and Business Administration, Saint Mary's College of California.

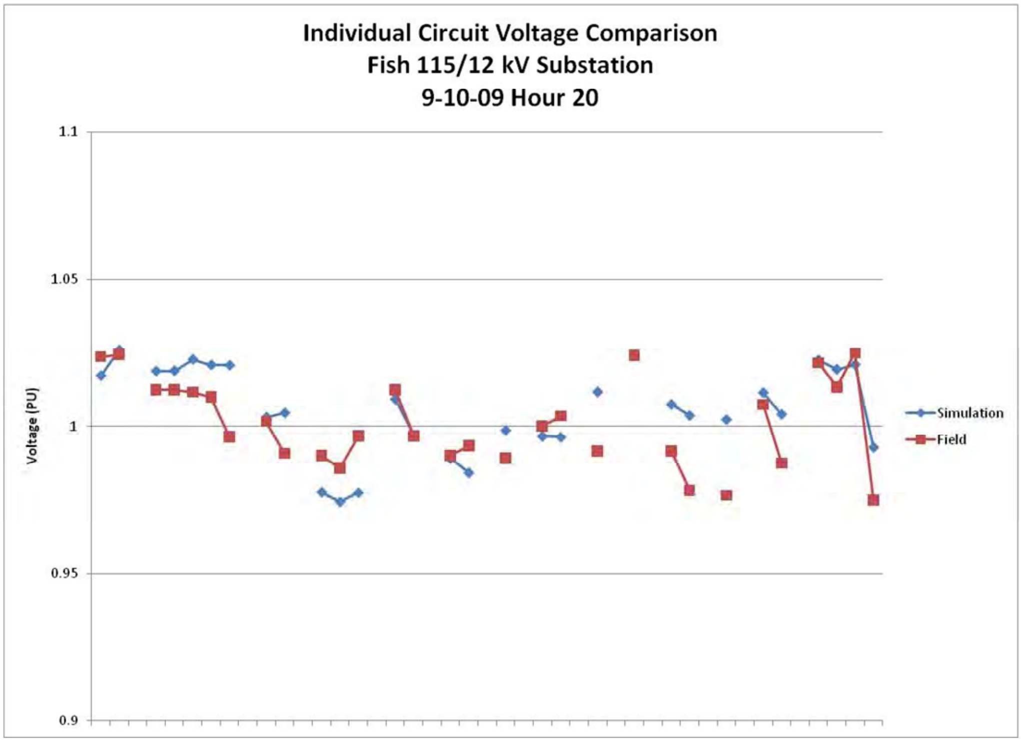

Figure 36. Fish substation circuit voltage profile comparison

The two substation buses with voltage instrumentation are on the far left, and the field and simulated voltage values extending out each of the substation's circuits are shown ranging to the right. The individual values match up reasonably well; moreover, the voltage *profiles* along the circuits evident in the field data are also captured in the simulation.

What is more important from a practical standpoint is the difference between the simulated and field-read voltages lies well within a ± 5% or even ± 2% range that might be of interest to a power system operator. In other words, if an actual voltage value were outside the range of ± 5% of nominal, the results in Figure 36 suggest that the simulated voltage at that location would observably follow the field value. Likewise, a simulated value outside that ± 5% of nominal range is a good enough predictor of an actual out-of-specification field value to warrant further investigation.

To test the sensitivity of the Energynet® simulation to changing conditions, the researchers developed a second dataset for Hour 14 of Thursday, September 10, 2009. Hour 14 has lower loads than Hour 20, and because it is earlier in the day, the impact of embedded photovoltaic generation in the Hobby system is different. The system was modeled as it stood a few weeks earlier, on August 3, 2009. The model was built up based on actual loads recorded for that day and hour, and capacitor device status reported through the distribution monitoring system for that day and hour.

Figure 37 is a comparison of simulated voltages with field-read voltages similar to Figure 35 but under the new set of system conditions. The center of the mass of points has moved slightly up above 1.0 PU, behavior that is reasonable for voltage given the lighter loads.

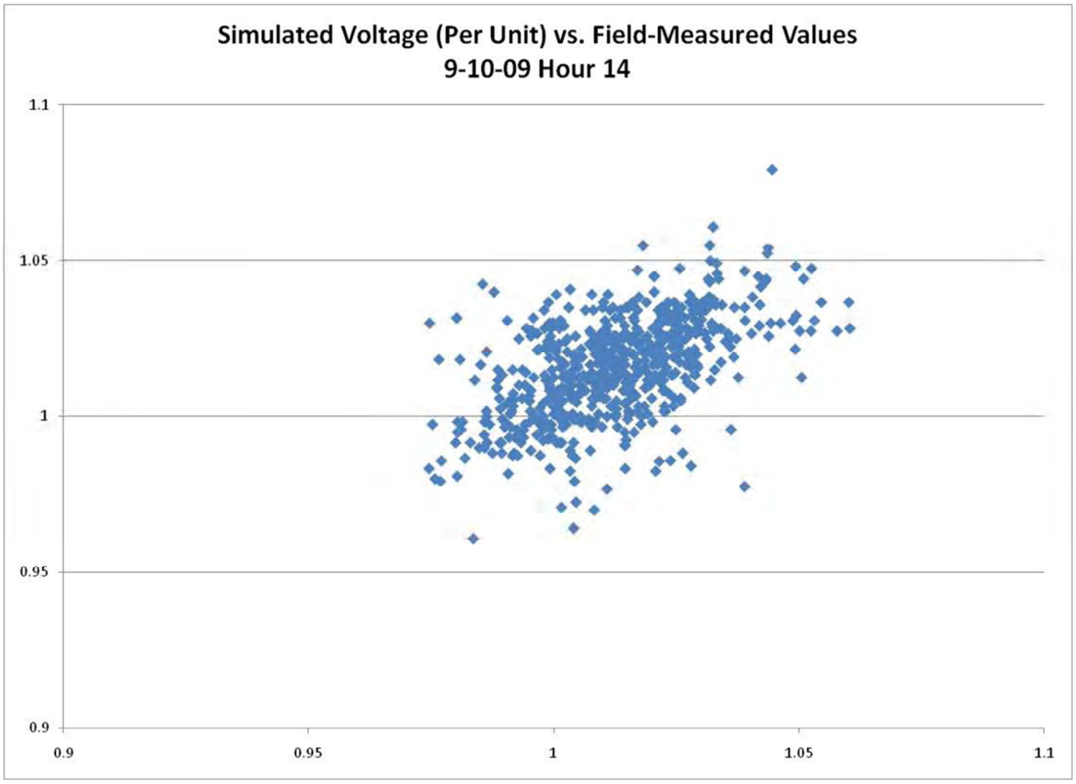

Figure 37. Voltage Comparison #2

A similar analysis as above suggests that the simulation values remain statistically representative of the field values. Therefore, the simulation has adapted and properly reflects the change in the field conditions. Pearson's r = 0.54 in this case is also a moderately strong numerical measure of correlation. The t-test also shows that the mean differences between the two data sets (field and simulation) are not statistically different from zero, meaning that simulation values and field values on average are still not different. The regression analysis shows that the simulation values remain statistically significant predictors of the field values with, in this case, 29.7% of the variability in the dependent variable (field values) explained or predicted by the independent variable (simulation values).

The researchers evaluated existing resources within the Hobby system (e.g. controls and existing DR) to see if their predicted influence on the system could be detected and validated with field measurements. The researchers performed a recontrols study on the 2009 Hobby verification model to assess how it would perform with ideal control settings. The impacts are described in Section 3.2.3. As stated there, the recontrols using GRIDfast™ optimization would reduce systemwide losses by about 1.4 MW and improve the systemwide minimum voltage by 0.026 PU, to where there are no buses with voltage lower than 0.95 PU.

Further, based on the simulation the researchers found that, under this optimized condition, the Hobby system's voltages are all within the ideal range and a P Index more negative than the average less two standard deviations is only -2.7. Therefore, it is reasonable to expect that small changes in resources, even in locations with relatively extreme resource deficiency or surplus, would have a very small effect (i.e., 1-2% at the very most) on field-observable conditions such as voltage.

The researchers also modeled 4,879 existing DR resources in the 2009 Hobby verification model. The researchers evaluated and ranked these using GRIDfast™ for their impact on voltage and losses under those conditions. The researchers found that of the total, 4,497 are measurably beneficial in terms voltage and losses. The predicted impact on these projects, in rank order, on the systemwide minimum voltage is shown in Figure 38 and on systemwide losses in Figure 39.

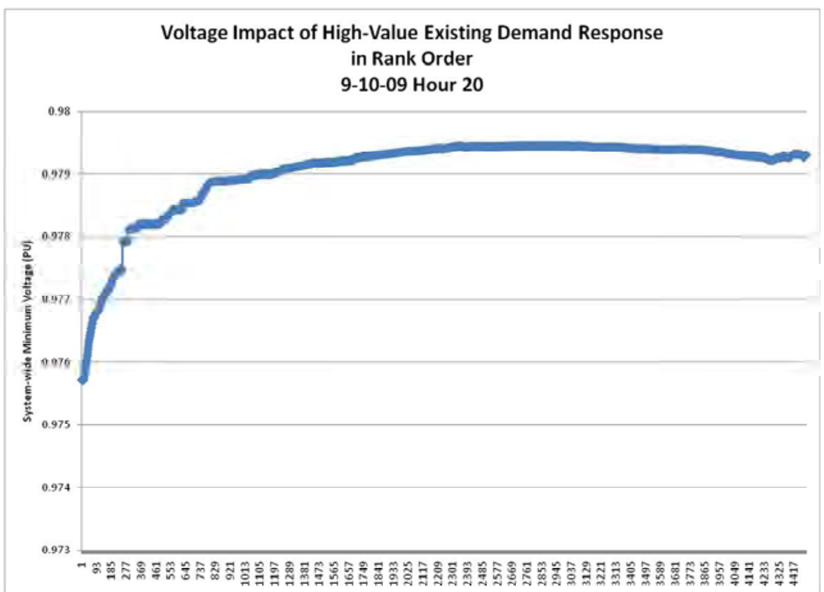

Figure 38. Voltage impact of existing DR

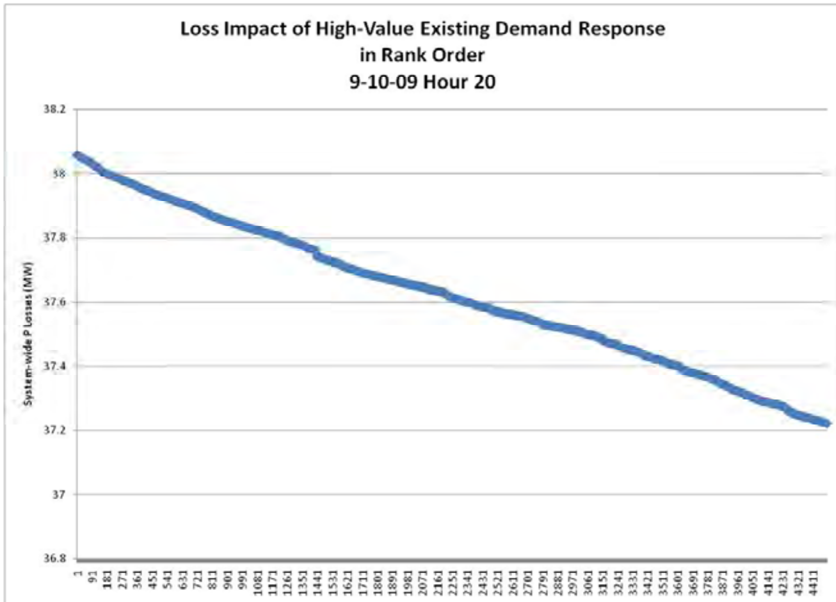

Figure 39. Loss impact of existing DR

Figure 38 indicates that, as the researchers found in the analysis performed for the 2005 Hobby system, there is a subset of existing demand response projects with a disproportionate impact on the systemwide minimum voltage. Figure 39 indicates that the loss impact of these 4,497 existing demand response resources is nearly linear, and there is not a subset with disproportionate loss impact. The researchers selected the top 257-ranked existing demand response resources, roughly the first inflection point in Figure 38, and mapped them in terms of total capacity by circuit. These are shown in Figure 40.

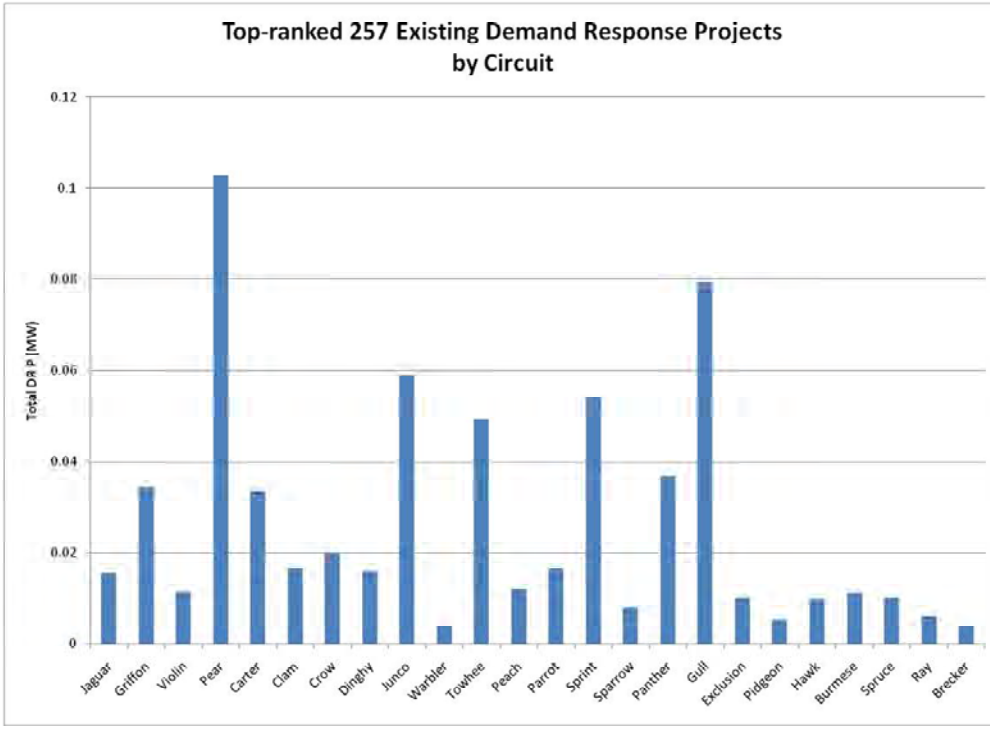

Figure 40. Top-ranked existing DR by circuit

Figure 40 indicates that there are about five circuits, e.g. Pear, Junco, Towhee, Sprint, and Gull, with relatively large amounts of existing demand response capacity with high value in terms of voltage impact. It is conceivable that dispatching these circuits' projects together might result in a change in voltage that would be visible in field measurements. However, the scale of Figure 38 is expanded, and even if all 257 of the high-value projects were dispatched at once, the change in Vmin would be only 0.002 PU, or 0.1% of nominal voltage; this would likely be difficult to detect in field measurements.

The researchers also modeled 25 existing distribution-connected power generation projects with defined operating profiles in the 2009 Hobby verification model. The researchers evaluated and ranked these using GRIDfast™ for their impact on voltage and losses under those conditions. The researchers found that, of the total, 11 are measurably beneficial in terms of voltage and losses. These projects are listed in rank order in Table 96. The impact on these projects in rank order on the systemwide minimum voltage is shown in Figure 41 and on systemwide losses in Figure 42.

Table 96. Hobby System high-value existing distribution-connected generation projects

Rank	Circuit Name	Substation Name	Operating Profile	Pmax (kW)	Qmax (kVAR)	Qmin (kVAR)
1	Drum	Music 115/12 (D)	Solar	29.8	-	-
2	Ellis	Modjazz 115/33 (D)	Hydro	7,900.0	3,950.0	-2,633.3
3	Cedar	Tree 115/12 (D)	PS	360.0	180.0	-120.0
4	Horseshoe	Ride 115/12 (D)	Solar	52.8	-	-
5	Loon	Bird 115/33 (D)	Cogen	1,100.0	550.0	-366.7
6	Barbera	Grape 115/12 (D)	Cogen	4,070.0	2,035.0	-1,356.7
7	Manganese	Metal 115/12 (D)	Solar	36.0	-	-
7	Oak	Tree 115/12 (D)	Solar	623.0	-	-
8	Iris	Flower 115/12 (D)	Cogen	60.0	30.0	-20.0
9	Copper	Metal 115/12 (D)	Cogen	60.0	30.0	-20.0
11	Drum	Music 115/12 (D)	Solar	38.6	-	-

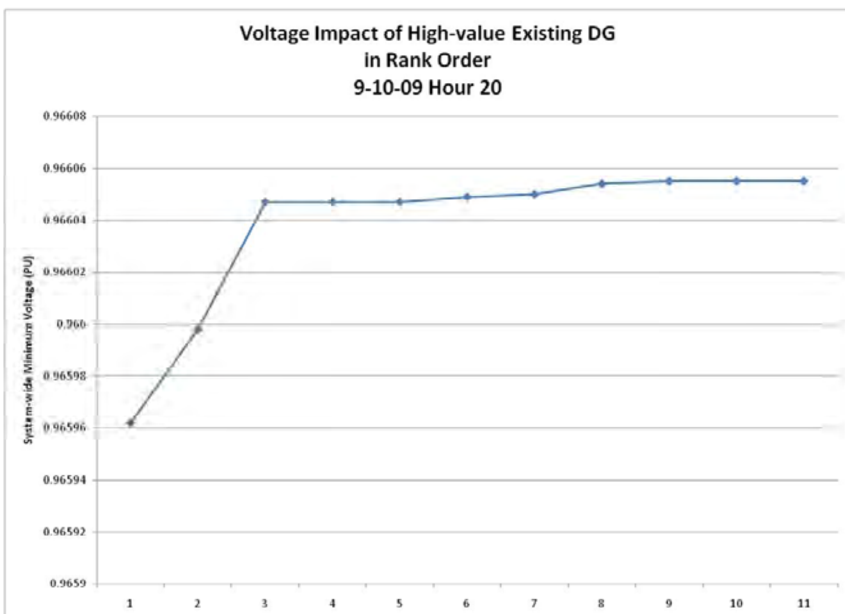

Figure 41. Voltage impact of existing DG

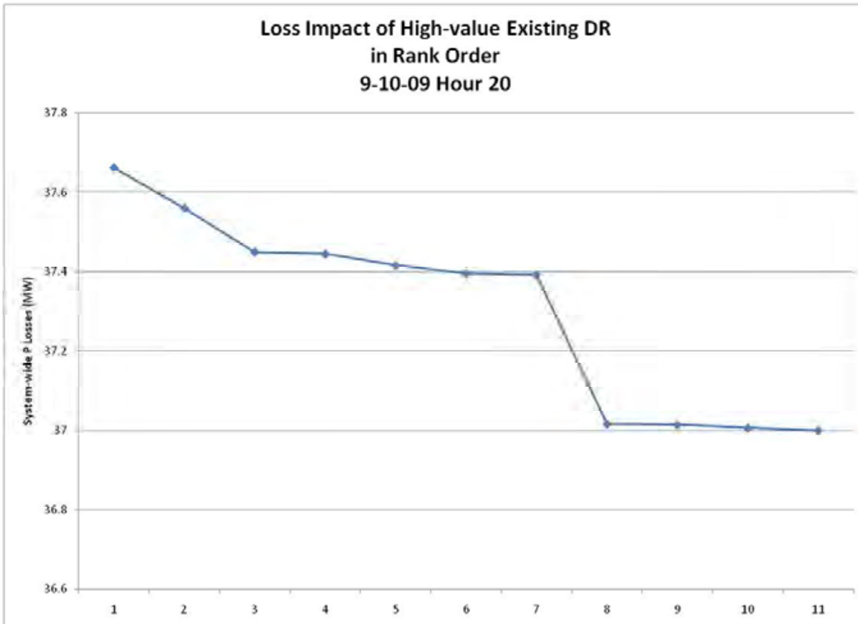

Figure 42. Loss impact of existing DG

Figure 41 suggests that the three top ranked projects, on Drum, Ellis, and Cedar circuits, have a disproportionate impact on systemwide minimum voltage. Figure 42 suggests that the project on Iris circuit has the largest single-project impact on losses.

The researchers also assessed all of the non-residential customer transformer sites in the 2009 Hobby system for the P "stress" at that location as indicated by the Resource Sensitivity Index or P Index as calculated by GRIDfast™ . The results are shown in Figure 43. Figure 43 shows that there are no customer sites in locations with positive P-Indices. This indicates that there are no customer sites in this group whose load actually benefits the system in terms of voltage or losses. Figure 43 also shows that within each customer class there are loads at locations with relatively extreme resource deficiencies; all classes other than Large Business and Industrial have a few customer locations with P Indices more negative than 2 standard deviations below the system average, or -2.7. It is possible that the curtailment of customer loads at those locations would result in a visible change in system voltage.

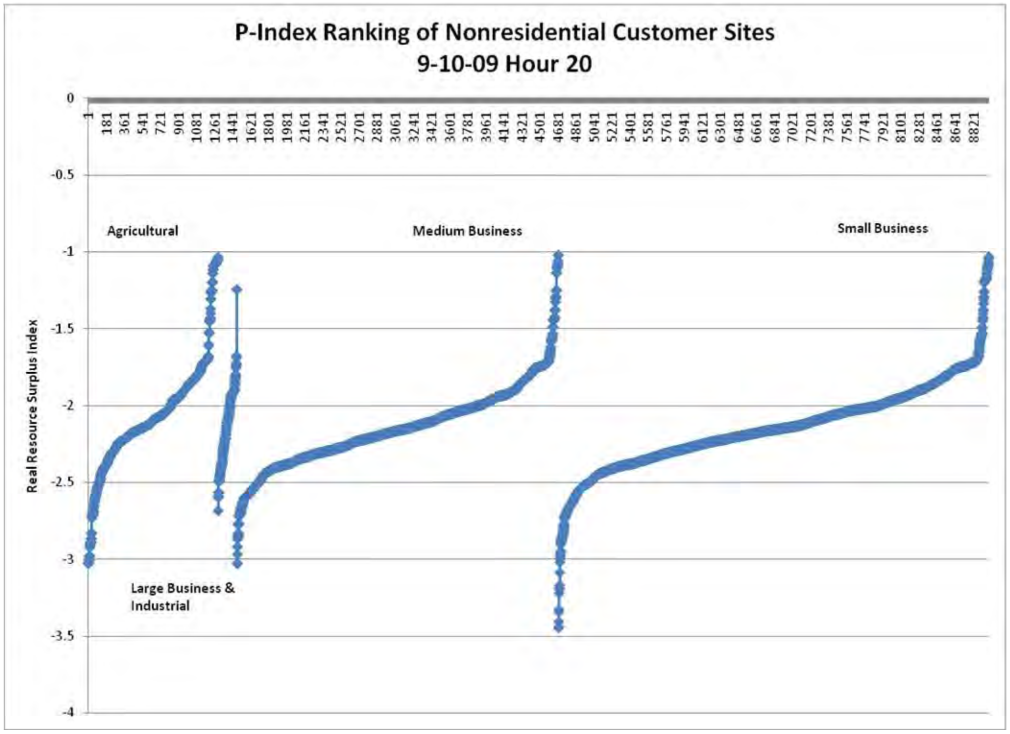

Figure 43. P-Index distribution of nonresidential customer sites

The researchers also performed for the 2009 Hobby verification model an assessment of the potential impacts of a "networking portfolio" of high-value switch closures as demonstrated for the 2005 and 2011 Hobby systems.

Figure 44 and Figure 46 show the simulated impact on the overall systemwide minimum voltage and losses from successive networking switch closures in the case under consideration. These are implemented in order from the most valuable in terms of voltage and loss impacts to the least. A key difference to note relative to the 2005 and 2011 Hobby system conditions is that the "as-found" systemwide minimum voltage in the 2009 system is already above 0.95 PU, so technically there is no opportunity to improve voltage by that measure. This is evident in Figure 44. Figure 45 confirms that there is nonetheless a cumulative but small voltage variability benefit from the networking switch closures. Figure 45 shows that the standard deviation of voltage in per-unit terms is declining, thus the voltage profile is getting flatter.

Figure 46 shows that there is a potential for loss improvement; however, this would require networking of half to two-thirds of the tie switches in the system; what benefits there are cannot be achieved with very limited networking.

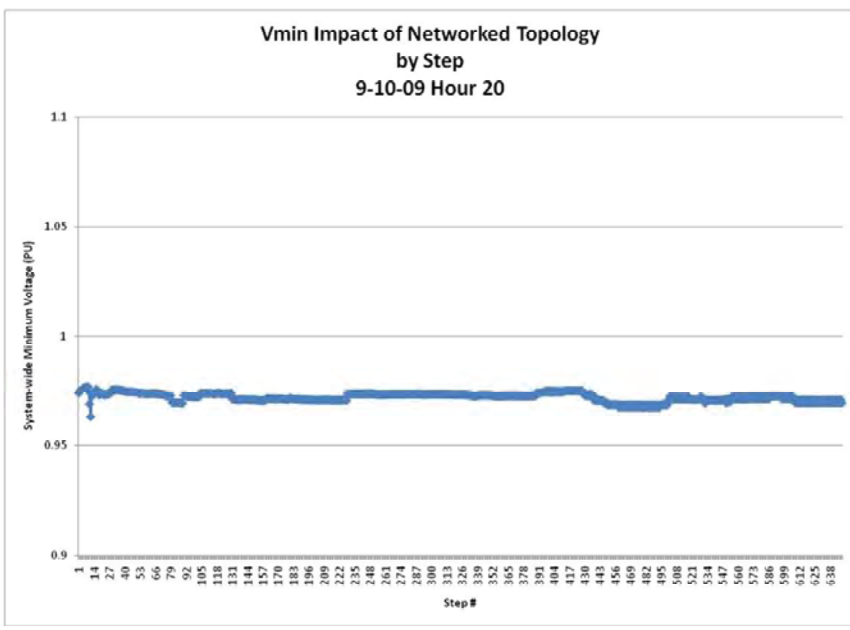

Figure 44. Voltage impact of networked topology

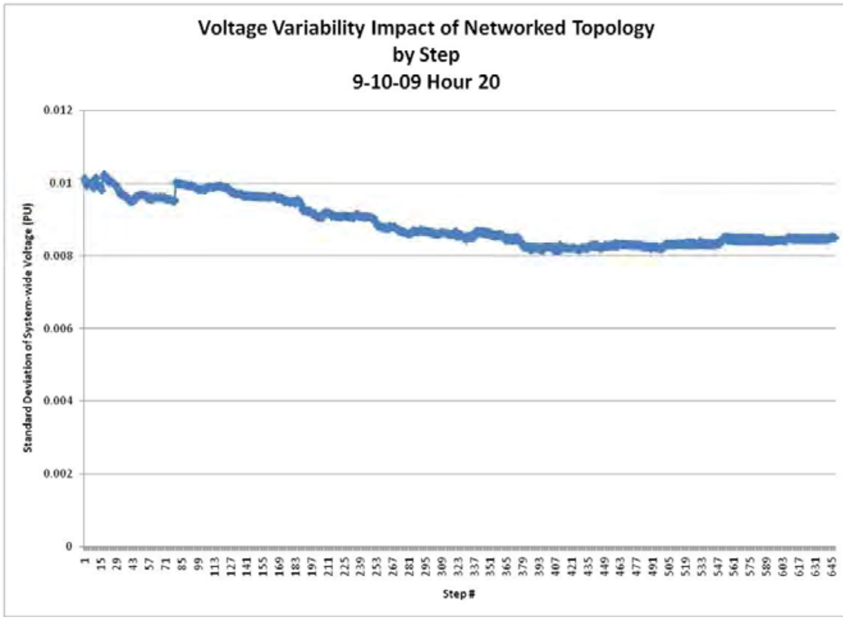

Figure 45. Voltage variability impact of networked topology

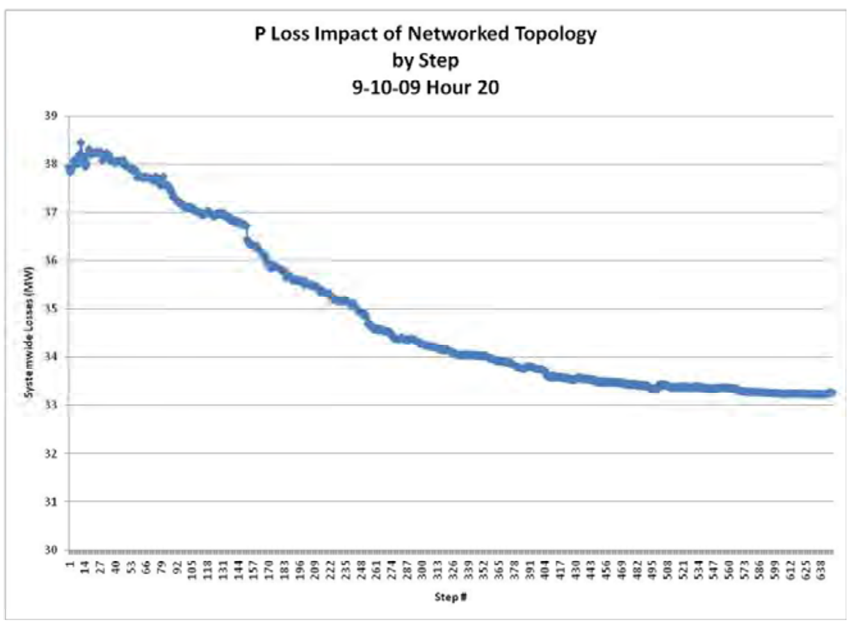

Figure 46. Loss impact of networked topology

These results indicate that while the researchers are able to identify high-value networking switch closures, under the present loading of the Hobby system the impacts of such closures would be very difficult to detect in field measurements.

These results meet the project's research goal validating the Energynet® model's characterization of the subject system as an integrated network with field measurements. Verification of the posited impacts of given network measures through field tests was one of the objectives of this project. These results indicate that there are measures that could improve the performance of the Hobby system in its present state at least under the conditions represented by the Hobby verification model. These include recontrols (revised capacitor dispatch and transformer taps settings) and a portfolio of limited networking steps. There are identifiable existing demand response and distributed generation resources within the system that have a disproportionate impact on voltage, and identifiable customer sites where resource additions would have a disproportionate impact. However, these are all relative conclusions. Given the light loading of the system and thus very small absolute values of these potential impacts, it is very unlikely that the expected impacts of these measures could be reliably confirmed through field measurements.

4.0 Conclusions

4.1. Conclusions

One of the four core research goals of the project was to demonstrate the application of the Energynet® methodology with its high-definition datasets in a larger, more complex power system and using source data routinely maintained by a utility typical of a California utility. Both of the full system models developed by the researchers for this project were over 100 times larger than the models developed for the SVP Project. In other words, the potential size of the model and the absence of an absolutely perfect, complete, single data source are not barriers to creating a high-definition model of a power system integrating transmission and the complete distribution system at the distribution element level. The results presented here also demonstrate that such a model can be updated frequently enough to support operational use in light of ongoing changes to the distribution system, confirming the practicality of the Energynet® model.

The researchers believe these are the only examples of the successful development of integrated transmission and distribution (T&D) power flow models of this scale from repurposed utility equipment and system data. Moreover, these results, combined with the field validation of this model completed in this project, indicate that a systemwide simulation with distribution element-level detail is feasible, practical, and a valid predictor of actual system conditions.

The second and third core research goals for the project were to demonstrate the capabilities of the methodology beyond idealized distributed energy resource (DER) placement and to demonstrate the practical value of the methodology for users to enhance power delivery network decision-making and problem-solving. The reliability analysis demonstrated in this project represents a quantification of the reliability benefits of individual network enhancement measures, thus beginning to support reliability improvement through targeted initiatives with quantifiable expected outcomes. The project's results show that reliability improvement could be a significant role for DER.

The simulation of traditional network expansion capital projects demonstrated in this project supports a direct, quantified assessment of load relief as a network benefit, both for these projects and for non-wires alternatives such as DER or topology reconfiguration. The simulation of these traditional projects also supports assessment of the impacts of these projects in broader terms, such as their voltage impacts, loss impacts, and reliability impacts, possibly supporting better-informed, more objective investment decisions.

The use of the methodology as demonstrated here to define operational scenarios for distribution automation and to identify key system elements whose automation would of significant merit could bring focus, yield increased value, and reduce the cost of distribution automation deployments.

The demonstration in this project of the use of this methodology to objectively assess the impacts of essentially operational network performance measures such as variable topology and optimization of control settings shows that such low-cost operational measures can yield significant benefits in terms of reduced losses and improved power quality.

The identification of Optimal DER Portfolio additions confirm prior conclusions that DER in specified locations and having specified attributes can enhance power network performance. In one important set of findings, the researchers found that distributed storage, even with targeted citing, can have significant voltage impacts under off-peak conditions due to their charging loads. These impacts are far from general, and in fact appear to be limited to a few circuits, and can be easily identified.

The economic benefits model applied in this project captures a comprehensive range of potential benefits from a wide variety of network measures, permitting a rigorous economic analysis of each measure and objective comparisons or rankings of potential measures. A key finding is that network expansion measures and DER can, in fact, yield system benefits having comparable value, but in different benefit areas.

The ability to directly assess the systemwide impacts of individual network performance enhancement measures and to comprehensively value those impacts relative to cost offers a preview of a process for evaluating such measures that is objective, rigorous, and data-driven (the most important considerations), that sidesteps misconceptions about the benefits of both traditional and non-traditional measures, and that captures a broad set of benefits relevant to a broad set of stakeholders. These results clearly show that the benefits of such diverse measures can be quantified and priced, and that rigorous project justification, even for new smart grid measures, is possible.

The fourth core research goal was to validate the methodology's characterization of the subject system as an integrated network with field measurement. In this report the researchers present results based on simulation results and field data reads in coincident, highly dispersed locations that show that the Energynet® model is a strong predictor of field conditions, accomplishing the goal of verifying the high-definition power system simulation used in this methodology.

The researchers believe the wide area monitoring system implemented in this project, covering over 200 circuits, is one of the most extensive monitoring networks of this type. Moreover, integrated with the system model, this represents a full-scale, field-verified, continuously updatable power system simulator with directly integrated system monitoring that can estimate the conditions at any point in the subject system down to a particular individual distribution element under past, present, or forecast conditions. This has important and unexpected implications for future smart grid deployments. Any initiative to enhance the performance of that power system by making it "smarter" can be evaluated and refined. The researchers accomplished this largely through the use of legacy equipment and communication infrastructure and at a very reasonable cost. Such an approach could accelerate the deployment of pervasive system monitoring to support grid-level smart grid systems and applications.

The remainder of Section 4.1.1 elaborates upon the project's conclusions, provides general observations, and identifies potential improvements in the approach employed within the context of each of the threads of this report.

4.1.1. Model Development

One of the core research goals of the project was to demonstrate the application of the Energynet® method with its high-definition datasets in a larger system and using source data routinely maintained by a utility typical of California's utilities. The results presented here fully accomplish this goal.

In the case of the Hobby system, the researchers have produced from different source data 15 separate models (so far), 7 reflecting the system on different "system dates," and 8 reflecting different possible future configurations. All have been verified as having no unintended islands or intercircuit ties. All but a few interim cases are populated with loads derived from actual SCADA records for a variety of conditions or forecasts and represent fully solved power flow simulations. The researchers have demonstrated that by going from raw utility data to a complete, checked model with several processing iterations in a few days.

The results presented here show that the information needed to characterize a power system as an integrated, distribution element-level model is already available within the host utility in some form, and that it can be adapted for this use. The researchers demonstrated that the inevitable missing data could be filled in with reasonable results.[34]

In other words, the absence of a perfect, complete, single data source is not a barrier to creating a high-definition wide-area model of a power system integrating transmission and distribution at the distribution element level. In fact, the researchers believe the only basic data requirements are the ability to identify physical devices, physical lines, line lengths, and how lines connect devices from any combination of data sources, compatible or not.

Significantly, one of the benefits of the Energynet® model is the ability to use the model itself to check data sources. A model is only as good as the data that go in. However, analytical results can identify those few data elements that, if correct, could have an extraordinary impact on system performance or drive decisions. It is a far easier matter to verify those few, consequential input values than to verify all input values. For example, an Energynet® simulation may reveal several circuits with line segments carrying current that exceeds their normal rating. In the 2005 Hobby system under summer-peak conditions, such segments probably represent a few hundred line segments out of nearly 90,000 segments in the system, or far less than 1%. It is very feasible to recheck, even if by hand, those few hundred to confirm both the correct conductor specification and the correct current-carrying rating.

These results also show that a systemwide, distribution element-level model reveals information about the subject system that would not be visible in a transmission-only model or in models of individual distribution circuits, confirming one of the conclusions of the SVP Project. At the system level, the integrated model reveals extremes in voltage and line segments

34. See also Evans, P.B., S. Hamilton, T. Dossey. February 2009. *High-Definition Modeling of Electric Power Delivery Networks*. Conference Proceedings, DistribuTECH 2009, February 3-5, 2009.

of interest in terms of VAR flow and loading within the distribution system that lie outside the observed performance bounds of the transmission portion of the system. At the circuit level, the Energynet® model reveals circuits of interest because they exhibit outlier condition when considered among all the circuits of the system operating together, as a whole network, in an internally consistent fashion. At the sub-circuit level, the Energynet® model reveals how the varying nature of loads on a circuit, the placement of and operation of devices on the circuit, the impedances of different conductor types installed in a circuit, etc., all affect the conditions on that circuit as well as the condition of the overall network.

One of the research goals of the project spoke of the practicality of such high-definition power system models. An important and unexpected finding in this project is that in a large utility environment a typical power delivery system may be vastly larger and more complex than the system the researchers modeled in the SVP Project, and may lie well beyond the practical limits of the dataset building techniques used in the SVP project. Therefore, in practice, "practicality" for an area-wide model having distribution element-level detail really means having fast and efficient ways to use data provided in forms and formats commonly used by a large utility to build the integrated datasets. This practicality goal is even more important now in light of this finding.

The Energynet® dataset for the Hobby system was built essentially entirely using software tools to extract and translate distribution system data in its raw form from SCE sources. Less than 0.01% of the data in the model required handwork. Importantly, the software-generated dataset is of very high quality. The researchers were able to verify that there are no spurious ties between circuits, that all circuits are radial, that there are no duplicate load-serving devices, and that are no unintentionally islanded buses. As indicated by field verification, the power flow results obtained from this dataset reasonably reflect the actual behavior of the network.

Software processes are by nature repeatable and scalable, so the researchers assert that this dataset building process could be repeated with a different system, even if larger or smaller. That repeatability and scalability is not demonstrated with an initial run, as it is intermingled with refinement of the software tools themselves. It can only be demonstrated through the processing of a subsequent system's data. A key question is whether these software tools are extensible – that is, whether they can be applied in a different data environment. The researchers believe they have identified the key elements common to any data characterizing a power system, so that differences among data environments are reduced to semantic differences that can be translated using software. Again, this can be demonstrated only through an actual application.

Another unexpected conclusion from this work is that for a large, rapidly growing system like Hobby, any information on the power system goes stale quickly. This study considered system conditions on four days in 2005 ranging from January to August, and a system configuration based on a November 2005 snapshot. In fact, the system in January 2005 was different than the system in summer 2005 or in November 2005. Circuits and components were both added and retired. Differences in the Hobby system from the 2005 model to the 2008 and 2009 updates were clearly visible; in fact, the models built for the 2009 verification studies revealed consequential changes within the system occurring from week to week.

This raises two practical needs, both related to dataset building, not specifically anticipated as this project commenced. The first is the need to build datasets quickly enough to use them before they are out of date, or to build multiple datasets reflecting the system configuration at particular times. The second is the ability to maintain a dataset once built.

Clearly software-based development of high-definition, integrated power system datasets is the key to rapid dataset building, as opposed to hand-building. Given this criterion, arguably software tools would be appropriate even for a small system that could reasonably be built up by hand.

With regard to dataset maintenance, there are two approaches. One is to simply rebuild the dataset from source data periodically to refresh it. Another approach is to put the system dataset in the update process for the source data, so that it is maintained automatically. The researchers have provisioned this second option by retaining all of the SCE numbering and naming conventions from the source data in the Energynet® dataset. This second approach was also successfully demonstrated in this project through the researchers' implementation of system data and system condition data transfer bridges. These data bridges fed updated data to the model automatically, largely using SCE's legacy data systems and features. Using this infrastructure the researchers implemented system model updates in days with little human intervention and almost no effort on the part of host utility personnel.

Another set of unexpected findings has to do with off-the-shelf power system analytics. First, the researchers demonstrated in this study the easy translation of integrated power system datasets into a standard format that can be directly read by commercially available power system analytic software. However, the researchers also found that the Hobby and Mountain system datasets are larger than could be accommodated by the most prominent power flow packages. This would be true even if the westwide high voltage transmission were excluded. This is evidently not an insurmountable problem, as GE successfully developed and was able to provide for the project a version of PSLF that would accommodate the Hobby model in its entirety.

Second, as the researchers' processing of source data became more and more automated, random human errors disappeared, while systematic processing errors became more prominent. The initial power flow solutions themselves emerged as a key error-screening step. Even a "complete," "connected" dataset will not support a power flow solution if the underlying data are internally inconsistent. PSLF in particular seems to be known for being unforgiving with respect to data. The researchers found this to be a benefit. Once the researchers know there is a problem, they have the ability to characterize it and find it. For these purposes, analytic package features that "solve through" data errors to obtain a power flow solution have benefits, but they also have a potential drawback in masking data errors that should and can be corrected.

The datasets underlying the Energynet® models completed in this project include the specific customer class rate or schedule of the customer(s) served at each load-serving transformer site. In the SVP Project, the researchers characterized each site only by the rating of the transformer, with no further information on the actual customer. In this study, this additional level of detail was possible in large part because the utility was able to provide data that could be mapped to individual points in the network.

The researchers believe this additional customer information is a significant enhancement to the model. Among other things, the researchers are able to identify at the individual bus level the existing demand response resources in the system, and make an assessment of the network benefits and ideal dispatch of those resources, as further discussed in this report. The researchers are also able to characterize potential distributed generation projects at each location appropriate given the specific type of customer at that site and assess the benefits of such projects.

4.1.2. Network Performance Improvement

Metrics and Indicators

This project started out with an approach inherited from the SVP Project that focused on voltage profile and losses as the most important indicators of network improvement. In hindsight, this may have been because the SVP system is not heavily loaded and generally free of overloads and also the researchers' use of tools borrowed from high-voltage transmission, which generally has the capacity to avoid normal-condition overloads.

In stark contrast, with the Hobby system in 2005 the researchers encountered actual persistent nominal overloads of individual line segments. Load growth in the Hobby system at that time was also so rapid that SCE indicated that at times it was difficult just to deploy the crews needed to get the upgrades built. In short, in this real world system, the operator's focus was far less on losses or voltage and much more on simply having the capacity needed to serve the load. This is evident in the set of planning objectives taken from the Hobby system capital plan discussed in Section 3.3.1.

So possibly a loss and voltage focus for network improvement is misguided in the real world. The researchers have noted in several places that this project suggests at least investigating the direct incorporation of loading and load relief in the analytical tools the researchers used to evaluate and rank network performance enhancement measures.

NCI in its benefits model has brought these perspectives together and moved them forward. Its approach, for its part, includes and firms the value associated with loss reduction and particularly voltage improvement. It is clear that there are these and other benefit categories in the NCI approach that offer substantial potential value but that most likely simply do not appear in most system plans or in power delivery system spending prioritization. Then, in these results, the researchers built on NCI's benefits model to further quantify and value the impacts of loading and load relief.

Investment Deferral and Load Relief

The references cited in this report demonstrate the ongoing level of interest (and belief) in deferral of T&D investment as a key value driver for distributed resources. The results presented here do not conclusively demonstrate that DER can usually, often, or easily defer T&D investment. This may be at least partly because the researchers' posited DER additions were not specifically identified for that purpose.

More importantly, however, the researchers' simulation of the 2011 Hobby system provides one illustration that not all demonstrated constraints are addressed by capital projects (at least in the near term) and not all capital projects address demonstrated constraints. Accordingly, as the researchers state in Section 3, they believe the entire notion of "deferral" is off target.

The Energynet® model permits a direct assessment of system loading (and identification of the system's overloads) at the distribution element level – at the level of individual circuits and substations. It also allows the direct observation of easy, possibly temporary measures to mitigate overload conditions such as load rolls or networking.

The researchers suggest that through these simulations and various load forecasts, ideally based on different operating conditions and a sequence of time periods, and also reflecting different sets of assumptions, demonstrated constraints involving individual distribution-level elements or specific *load relief* requirements can be identified. Through further simulations, the near- and long-term efficacy of various measures, including both network expansion measures and DER, in providing this load relief could be objectively assessed.

Reliability Assessment

The results presented here demonstrate the ability of this methodology to distinguish differences within a power delivery system's overall theoretical reliability (or vulnerability to random contingencies) down to at least the individual circuit level. Importantly, the researchers found that there are vast differences in the theoretical risk for unserved energy among the circuits in these power systems. Even allowing for randomness of individual contingencies, these theoretical reliability differences arise from topology, including circuit layout and post-contingency load shift opportunities, levels of loading on transformers and lines, substation design, and levels of automation. Interestingly, of these factors, load shift opportunities, not individual component loading, appear to be the most important.[35]

It is not surprising that some portions of a power system may stand at far greater reliability risk due to these factors; these results show these nominally risky areas can now be identified and possibly addressed.

Possibly more importantly, this reliability approach demonstrates the factors affecting differing levels of reliability within a power delivery system the features of individual network measures that meaningfully affect reliability, including project location, size, and availability.

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35. See also P.B. Evans, March 2010. *Power Delivery System Reliability Assessment Using High-Definition System-wide Model*, Conference Proceedings, DistribuTECH 2010, March 23-25, 2010.

Once it is known that a given circuit has an unusually high risk of unserved load because it has few alternate sources and/or those are loaded to where they cannot accept post-contingency load shifts under say normal summer peak conditions, any one of a number of projects might alleviate that condition. The one thing they must all do is provide additional post-contingency load shift capacity for the circuit in question during normal summer peak hours. Depending on the value planners place on reliability improvement, these results suggest that the ability to reduce system loading in targeted locations, even variably or under limited conditions, where that load reduction expands post-contingency load shift opportunities may emerge as an important value driver for DER.

An important next step in this granular analysis of reliability is the linking of information from outage post-mortems and root-cause studies to the factors used in this type of a study, building confidence that the factors used in such a study could prove by demonstrating to be predictive of real-world failure rates and customer outages.

Voltage

As stated earlier, voltage impacts were one of primary considerations in the evaluation of network measures in this study. At the same time, in the SVP Project the researchers quantified voltage impacts of DER and other network measures but did not establish a value for voltage improvement as a benefit. In the SVP Project's conclusions the researchers stated that the SVP Project showed the ability of DER to provide "voltage support" benefits if properly sited and operated and the ability of the Energynet® methodology to determine how and quantify how much, yet the inability to put dollar values on such benefits remained a challenge that should be addressed.

In this study, the researchers also did not value "voltage support" as a benefit category. However, NCI did identify three specific sources of value from voltage impacts – power quality improvements (and related impacts on interruptions of customer processes), the impact on the potential for conservation voltage reduction, and T&D O&M cost savings due to less voltage variability. Simply enumerating these value components is an important step toward placing a value on voltage improvement as a potential network benefit.

The researchers were partially successful in assessing the true value of the voltage impacts of the network measures evaluated in this project. As stated above, the researchers' analytical approach could be refined to directly reveal the voltage variability (and power quality impact) at specific customer sites due to any given network measure, and to assess the extent to which a given measure expands opportunities to implement CVR.

Most importantly for future considerations, the researchers also showed that power quality is a relatively large value component (albeit a customer value), and that importance of CVR could be much higher than the values the researchers used in this study. It is conceivable that with basic load relief requirements met, the voltage impacts of network measures and their influence on power quality and the ability to implement CVR could be dominant planning drivers.

The researchers also struggled to find a clear indicator of the direct impact of given measures on system voltage. In most cases, the researchers considered the change in overall system minimum voltage as one measure; however, the researchers found that even with the GRIDfast™ hysteresis described below, this measure is often too "noisy" to use to assess the impacts of individual projects; the noise arises from other factors changing in the system such as capacitors and tap changers.

Network Enhancement Measures

Recontrols

The results presented here clearly show the opportunity to improve network performance through improved control settings, in this case using GRIDfast™ . However, finding the right control settings presented some unexpected challenges.

The researchers found that under many or most of the system conditions the researchers have modeled it is not possible to manipulate available system settings such that voltage limits of 0.95 to 1.05 PU are met at every bus. The researchers also found that with no voltage limits imposed GRIDfast™ might recontrol the system to further reduce voltages at already low voltage buses to achieve lower losses. To mitigate this, the researchers imposed individual bus-level low-voltage limits for GRIDfast™ equal to the as-found voltage at that bus. This ensures that no recontrol solution will reduce voltage at any bus to below its as-found voltage.

However, the researchers found in the DER addition steps that these revised lower voltage limits had the unintended result of directing GRIDfast™ to add resources and re-optimize the system for a voltage range that would tolerate relatively low voltages. To illustrate, the researchers found that while the variability of voltage fell dramatically as resources were added, nominally low-voltage buses (e.g. under 0.95 PU) remained. Under normal summer peak conditions voltage variability fell from nearly 3.0 percentage points PU under "as found" conditions to nearly 1.5 percentage points PU with all DER in place; at the same time, the low-voltage buses that remained with the DER additions in place were nearly all around 0.94 PU.

Based on this, the researchers feel low-voltage limits within GRIDfast™ , if handled differently, would probably yield better results than what the researchers obtained here. One approach would be to apply a ratcheting low-voltage limit at each stage of resource additions. This might eliminate all low-voltage buses while still bringing systemwide voltage into the same narrow range.

The researchers also discovered that the discrete step character of the TCULs and capacitors creates a complication in the GRIDfast™ DER addition runs. As resources are added, small changes in system conditions can cause TCUL or capacitor moves that are relatively large. This causes "noise" in very focused results such as the systemwide minimum voltage. The researchers also found that as capacitors are added at negative Q Index buses the TCUL in the substation serving the circuit may step, causing low-Q Index buses on other circuits served from that substation. The capacitor addition will then add resources to those low Q-Index buses, and the cycle continues.

To address these issues, the researchers introduced hysteresis within GRIDfast™ in the recontrol of TCULs and capacitors and in the addition of reactive power resources at negative Q Index buses. In effect, these are dead bands within which a TCUL or capacitor will not step or within which GRIDfast™ will not add resources. These result in slightly sub-optimal solutions but less "noisy" and more realistic results.

DER Additions

As in the SVP Project, in this project the researchers were able to identify specific DER additions that could enhance the performance of the subject system in quantifiable ways. These beneficial projects are individually identified by location, size, and operating profile, and are suited to the characteristics of the "host" customer at that site. The researchers can state unequivocally based on these results that within a power system not all DER projects are beneficial, while some are very beneficial, and that their locations and characteristics are important.

One important finding is that system conditions and the value of any particular DER measure are very different under super-peak conditions. This is due not only to greater system loading, but also to the researchers' assumption of much greater availability of demand response. This conclusion is evident in this study because the researchers included residential and small business customer sites as potential demand response sites, where the researchers did not in the SVP Project. As one example of their impact, the researchers found that distributed generation additions that provide voltage benefits under normal summer peak and winter peak conditions provide *no* voltage benefits under super-peak conditions after consideration of available demand response.

This suggests first that demand response is a very potent DER alternative – perhaps the most potent – for addressing super-peak conditions if residential and small business demand response continues to be developed. It also suggests that with an effective demand response implementation the benefits of other DER measures may be realistically limited to non-super-peak conditions.

In this study, the researchers allowed demand response at every eligible site, which under super-peak conditions was nearly every customer site. This is a theoretically valid approach; however, some might argue it is far from realistic. Also, CERTS, in its spinning reserve study, found that the actual demand response capability from HVAC cycling demand response is highly dependent upon weather. In any case, the researchers' assumption resulted in the incorporation in the 2005 super-peak condition simulation a massive amount of demand response. This in turn affected the assessment of the benefits of distributed generation and storage opportunities under those conditions. Therefore, to obtain a "realistic" assessment of the benefits of distributed generation and storage, the researchers would need to limit in some theoretically valid way the volume of demand response the researchers assume under super-peak conditions.

Another important finding of this work is that many existing demand response resources in this system, when evaluated and dispatched correctly, are valuable as *system* resources. The researchers identified individual projects among these resources that provide significant voltage benefits under super-peak conditions. It is likely that a closer look at these resources will show that certain existing demand response resources, if dispatched in a coordinated fashion, could provide valuable relief from temporary overloads that occur under super-peak conditions.

Storage

There is strong evidence in this project's results that the loads associated with storage devices can have adverse effects on a power delivery system during off-peak periods at least under some conditions. Specifically, if storage devices are placed where their capacity can yield network benefits, the off-peak load associated with those storage devices may cause stress in those locations. In addition, these effects may be hidden under simple voltage analysis. Further, these problems may not necessarily emerge where there is a large amount of storage capacity; the impact of this additional load on weak parts of the system is evidently more subtle. Nonetheless, if this system is any indication, some consideration given to placement and maximum charging rate or sizing of these devices can address the problems.

The researchers chose an approach that would directly consider and balance on-peak and off-peak effects of storage additions by considering the difference in P index at each location in the system. An alternative approach would be to place storage solely for its on-peak benefits, then address potential off-peak problems indirectly by restricting candidate sites or even simply limiting charging rates.

It was difficult with this set of results to discern significant benefits to the performance of the grid on peak resulting from storage additions, and particularly difficult to discern the differences between the different storage scenarios in terms of on-peak grid impacts. These distinctions could be masked in this case by two factors. First, the voltage limits enforced in these optimizations were taken from power flow voltages from sub-optimized cases, and were therefore not very "tight." Enforcing voltage limits more appropriate for the state of the system prior to the addition of storage might better highlight the impact of these additions. Second, the on-peak configuration of the system before the addition of storage already included significant optimization, including recontrols, ideal capacitor additions, dispatch of existing demand response, and placement of considerable additional demand response capacity. Even though the researchers did not include in the super-peak case all of the beneficial demand response or any of the beneficial distributed generation identified above for these conditions, the level of real power stress immediately prior to the storage additions may still be unrealistically low for a super-peak case. With little system stress and forgiving voltage limits, it makes sense that it should be hard to see the benefits of incremental capacity additions.

The researchers chose one scenario for the development of storage projects for the Optimal DER Portfolio – essentially a given share of peak load deployed as storage devices distributed within the system. This is an assumption that the charging load would be slightly greater than the rated capacity of the resource, and even an assumption that the storage would serve as a resource and a recharge load at the same location. Obviously other scenarios should be considered. For example, a storage device might charge over several hours at a relatively low power level to reduce its burden on the system, then discharge at many times the charging rate to provide a significant amount of effective capacity and related operational benefits. One variant of storage, an electric vehicle serving in a "vehicle to grid" (V2G) capacity, might serve as a resource in one location and a charging load in another. It might also place a full charging burden on the system, but offer only a share of its capability as a grid resource. These scenarios all have different implications for storage as a resource, and the researchers' finding that storage as a load may introduce system issues has different implications for each of these scenarios.[36]

The researchers also did not fully explore the full set of capabilities of battery-based storage, including the ability to provide essentially instantaneous capacity or the ability to provide reactive power. These considered alongside the specifics of the system might dictate different ways to deploy storage in an "optimal" portfolio.

As noted earlier, specific storage strategies such as those involving multiple layers of distributed storage and specific purposes such as augmenting intermittent renewable resources within the distribution system have evolved since the framing of this study. The researchers believe the Energynet® model would be a powerful tool to objectively evaluate the specific network performance benefits and economic value yielded by these storage strategies, and to help identify those storage applications that best justify the cost of storage devices. By way of illustration, the results presented in this project indicate greater overall system benefits from distributed resources that are more distributed- resources placed at sturdy locations on the three-phase main portion of a circuit contribute relatively less in terms of incremental network performance improvement. If this pattern were borne out in a storage study, it may suggest that strategies involving smaller, more distributed storage that is ideally placed could yield greater overall network benefits or benefits in a greater number of benefit categories.

Alternate Topologies

In this project, the researchers demonstrated topologies different from the generally radial topology of the Hobby system that would provide improved network performance in terms of losses and voltage profile. These topologies are partially networked and radial, both of which are feasible, and use only existing switches. The researchers also demonstrated systematic methodologies using the Energynet® simulation and GRIDfast™ to identify the individual switches to be manipulated to obtain these benefits and quantified the performance improvement.

Radial topology reconfiguration is methodologically different from networked topology because of the need to identify a second, re-radializing switch to open after a switch closing. This introduces some subjectivity and the need for important methodological features. Because in this project both the networked topology and the optimized radial topology approaches incorporated the same analytical optimization objective, the researchers can directly compare the two sets of results. It appears that even lightly networked topology is a more potent approach than even optimized radial topology in terms of mitigation of low voltage and loss reduction.

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36. See also Evans, P.B.; Kuloor, S.; Kroposki, B., *Impacts of Plug-In Vehicles and Distributed Storage on Electric Power Delivery Networks*, IEEE Vehicle Power and Propulsion Conference, 2009. VPPC '09. IEEE , pp.838-846, 7-10 Sept. 2009 doi: 10.1109/VPPC.2009.5289761 URL: <http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5289761&isnumber=5289440>

Networked Topology

In this project, the researchers demonstrated in the simulation that full networking of all of the 563 intercircuit tie switches of the Hobby system would yield reduced losses and improvement of the system's overall minimum voltage. As indicated, these outcomes are in part a function of the optimization objective chosen for the GRIDfast™ analytics that focus on losses and voltage deviation; as one example, the networking study approach did not explicitly take into account line loading.

More importantly, the researchers showed that networking a specific small subset of the candidate switches would yield most of the voltage benefit of a fully networked system. The researchers showed that those individual switches can be identified; as might be expected. Further, with these high-value switches only a small number of Hobby circuits would participate in this partially-networked topology. The researchers identified high-value networking closures under a variety of conditions to establish a "portfolio" of networking switches that would be implemented and reconfigured periodically as operating conditions change over the course of a year.

This "portfolio" of switches, if networked as described, would yield quantifiable voltage improvement and loss reduction. The improvement in the overall system minimum voltage ranged from 4.5% to 4.7% of nominal under summer peak conditions to 1% of nominal under winter peak conditions. The researchers estimated the loss reduction from the networking portfolio as ranging from 1.0 to 1.3 MW under summer peak conditions to approximately 210 kW under winter peak conditions. The portfolio consists of 38 tie switches, 7% of the total, and affects 52 separate circuits, 24% of the total. So the scope of addressing other implications of networked topology, such as more complex operating behavior and design requirements, is confined and also may be directed to those areas where networked topology is posited to yield network performance benefits.

The reliability analyses the researchers performed did not directly consider the benefits of networked topology, and the researchers did not consider reliability improvement in the researchers' evaluation of networked topology. Improved reliability is potentially an additional benefit of networked topology, and could be objectively assessed combining the approaches presented here.

Optimized Radial Topology

Periodic reconfiguration of radial topology is a normal distribution system planning evolution. What is presented here is an analytically driven approach seeking to achieve a specific, specified objective. In these results, the researchers have demonstrated an analytically driven radial topology optimization approach, in this case driven by GRIDfast™ analytics, which did yield alternate radial topologies for the Hobby system that would result in reduced losses and improved voltage profiles.

Some of the most important conclusions are methodological. An analytically driven radial topology optimization approach must incorporate some method for identifying the re-radializing switch, and that approach must take into account the direction of the shift and its size, and ensure that the resulting topology post-shift is in fact radial with no islands. Also, reconfigured radial topology under one set of operating conditions may not be an improvement under other operating conditions, so an analytically driven topology optimization approach should consider a variety of operating conditions.

The researchers found in this study that a methodological element permitting the reversal or the augmentation of a particular switch closing/opening "step" is an important feedback. It may be impossible to assess the impact of the step until it is implemented. This illustrates one of the key benefits of using a systemwide simulation such as the Energynet® model in topology reconfiguration – the model permits low-cost pre-assessment of alternative topologies without putting customers, personnel, or equipment at risk in an experiment.

The researchers combined studies of a set of topology-optimizing steps over different operating conditions to produce a portfolio of radial topology optimizing steps. For the 2005 Hobby system the changes would involve 102 individual switches and affect 58 circuits. Importantly, only one of these changes would be appropriate under all of the conditions the researchers evaluated. This suggests that to maintain "optimized" radial topology under changing conditions would require a flexible switching regime. This portfolio of steps once implemented as directed would provide an improvement in systemwide minimum voltage ranging from 3.7% to 5.6% of nominal under summer peak conditions to 0.81% of nominal under winter peak and off-peak conditions. The posited loss reduction was small to negative under all conditions.

It is worth reiterating that this topology optimization study yielded these results when GRIDfast™ analytics were programmed with an objective of loss and voltage deviation limitation. Therefore, load reduction, a reasonable objective of topology reconfiguration, was only an indirect benefit. This did permit a direct comparison of optimized radial topology with networked topology as different alternate topology approaches. It appears that even lightly networked topology with networking ties in the right locations is more potent than optimized radial topology in mitigating low voltage and reducing losses under prevailing normal summer peak and winter peak conditions.

Benefits of Distribution Automation

Essentially, distribution automation offers the potential for more flexible, more responsive, and ultimately higher-performing electric power delivery systems. The results presented here demonstrate the use of the Energynet® power system simulation to make two important assessments:

- Identification of those individual system devices that will yield the most benefit through automation.
- Quantification of potential benefits of automation.

Such information could support distribution automation projects that yield greater benefits for less cost, as well as greater rigor in substantiating distribution automation investments.

The researchers showed in this project that condition-responsive capacitor dispatch in a power delivery system could yield significant voltage and loss benefits. More importantly, the results presented here also suggest that not all capacitors are equally important for automated, condition-sensitive dispatch. The researchers present a methodology for determining a given capacitor's ideal operating profile to maintain high-performance system configuration, by inference a set of control requirements, and identify which capacitors in the Hobby system should receive each attributable set of controls. By doing so, the researchers identify sets of individual capacitors that would yield the most system performance benefit through application of a specific type of controls having varying levels of sophistication (i.e., ranging from always ON to variable operation based on an intelligent assessment of system conditions).

The most important conclusion in the researchers' opinion is possibly that the majority of the capacitors in this system would not be able to deliver their ideal operating profile under varying conditions with simple timer-operated controls. If this is typical, it suggests that utilities should be moving to design policies reflecting greater use of automated capacitors over timer-operated capacitors in general.

These results reflect the simulated use of a particular optimization method, GRIDfast™, in a single-point, systemwide control scheme. Further research could compare these results with the projected impacts of more distributed capacitor control schemes.

Within the Hobby system there are over 4,500 circuit sectionalizing and tie switches that could conceivably be automated for remote operation (of which about 233 presently are automatic or remotely operable). In this project the researchers demonstrated two topology optimization schemes, a partially networked scheme and an optimized radial topology scheme that would yield quantifiable system benefits in terms of system minimum voltage and losses. The researchers also showed that for the 2005 Hobby system the partially networked topology scheme would involve frequent manipulation of 19 individual high-value switches to accommodate varying conditions, while the optimized radial topology scheme would involve frequent manipulation of 100 individual high-value switches.

The researchers also identified 98 circuits out of 215 in the 2005 Hobby system that would derive a theoretical reliability benefit purely from increased switch automation alone; that is, where other factors would not eclipse the benefits of automation.

This shows that through this methodology the researchers can individually identify a very small share of the system's switches as high-value for automation to achieve stated objectives, and that the benefits of that automation can be discretely quantified.

The researchers also identified a small share of the existing demand response resources in the Hobby that provide demonstrable benefits in terms of system voltage improvement and loss reduction, in addition to their demand reduction benefits – in other words, these specific demand response projects have value as system resources as well as demand reduction resources. To realize the additional benefits of these particular demand response resources, the researchers argue that these resources should be individually dispatchable. The researchers note that that most of these resources lie on a few circuits.

The researchers found that of the 13 existing distribution-connected generators in the Hobby system, very few would be dispatched at unity power factor or at a single VAR output level under optimal dispatch using GRIDfast™ under varying system conditions. This suggests that the VAR capability of distribution-connected synchronous generators has value in maintaining a high level of network performance under varying conditions. While the researchers did not quantify the impact of VAR output from these particular resources, automated control of the VAR output of synchronous distributed generation is worthy of consideration for the network operator to gain access to through automated, remote dispatch and appropriate contractual provisions.

It is worth noting that synchronous generators are generally found at larger customer sites and often involve contact with the network operator during interconnection, conditions that might facilitate the incorporation of automation capability. At the same time, modification of existing distributed generation device controls might be prohibitively expensive.

DER, Operational, and "Traditional" Network Expansion Measures

In one portion of this project, the researchers evaluated an "expanded" set of network measures, including DER, operational measures, and traditional network expansion measures for their ability to address a given set of system planning and operational objectives. The results show three things:

- **In a side-by-side comparison, there are instances where DER projects can provide the same benefits as traditional network expansion projects, possibly with greater flexibility.**

In this study, the only clear example of this is in load relief for the Music substation. Potential 2011 Optimal DER Portfolio project capacity is more than enough to avoid an overload confirmed by a system simulation with forecast loads, potentially deferring a planned transformer addition. As discussed below, it is possible that other such instances would be identified through an approach for identifying "valuable" DER projects more focused on load relief.

- **Not all system needs are addressed in the capital plan.**

At one level, this is stating the obvious, as not all proposed projects are approved and not all approved projects are built. At a more important level, this study and its use of systemwide, element-level simulation with forecast loads reveal issues that are apparently not addressed in the plan. One example is the overloads at Author and Boat substations. Another example is the Cloud substation project, which addresses several system needs that were confirmed in the 2011 Hobby simulation but is not planned or completion until after 2011.

- **Not all traditional network expansion projects address anticipated system needs.**

The simulation of the network expansion projects in the 2011 Hobby model suggests that the Starling circuit project resolves an overload at Metal substation that appears to be also addressed through a load shift, and that the project has minimal additional voltage, loss, or reliability benefits. The proposed transformer addition at Mayberry does not address substation overloads confirmed in the 2011 simulation, though the Paint transformer project does provide some reliability benefits.

The researchers believe this shows that potential “T&D deferral” value as a potential benefit of DER is misapplied. DER projects that “defer” a T&D capital project that itself does not address a real system need should not be viewed as having value as a result, and DER projects that could address a system need that is not otherwise addressed by a potentially deferrable T&D capital project should be viewed as having value. A more robust approach is to evaluate objectively the impacts of many possible solutions against a common set of metrics.

An important conclusion relative to assessment of even traditional network expansion measures is that the Energynet® simulation of the subject system with forecast loads is a powerful tool for assessing network planning needs. Load forecasts imply needs, but alone they cannot predict how the system may accommodate those needs and what system issues those loads may surface. In many instances, this project’s 2011 Hobby system simulation results confirmed the needs implied by the Hobby system capital plan projects, attesting to the planners’ understanding of their system and how anticipated load growth will affect it. At the same time, some needs implied by the capital plan did not emerge in the forecast simulation.

For the 2011 Hobby system, the researchers developed a single forecast case incorporating normal peak conditions. An analysis of this type would be improved with additional cases reflecting seasonal and diurnally varying conditions. The researchers’ results throughout this project show that the power delivery system changes character under different operating conditions. Capturing the impact and benefit contour of these potential network measures across a variety of operating conditions reduces the chance that an apparently attractive approach having merits (or availability) only under a limited set of conditions will eclipse a less compelling but more durable approach that is ultimately more valuable.

4.1.3. Cost/Benefit Analysis

In this project the researchers successfully demonstrated the valuation of the network benefits of an expanded set of network performance enhancement measures using a broad, consistently applied set of benefit categories. The network performance measures included traditional network expansion projects, DER, and essentially operational measures such as optimization of controls and alternative topologies, and the evaluation supported an objective, side-by-side comparison of these measures. The researchers also valued the benefits of each of these network measures in economic terms.

Accordingly, the results summarized in Section 3.1.12, particularly the summary for the 2011 Hobby system, offer a direct, side-by-side, objective comparison of the merits of a diverse set of network measures in dollars per year terms. These measures range from operational (ideal controls and topology reconfiguration) to traditional (new circuits and substations) to non-traditional (distributed energy resources). These results clearly show that the benefits of such diverse measures can be quantified and priced, and that rigorous project justifications, even for new smart grid measures are possible.

The researchers found that the benefit category (excluding energy and load relief) with the greatest value contribution for these measures is bulk system capacity followed by losses. This conclusion is identical to the researchers' findings in the SVP study.

As stated earlier, voltage impacts were one of primary considerations in the evaluation of network measures in this study. At the same time, in the SVP Project the researchers quantified voltage impacts of DER and other network measures, but did not establish a value for voltage improvement as a benefit. NCI identified three specific sources of value from voltage impacts – power quality improvements (and related impacts on interruptions of customer processes), the impact on the potential for conservation voltage reduction, and T&D O&M cost savings due to less voltage variability.

The researchers were partially successful in assessing the true value of the voltage impacts of the network measures evaluated in this project. The researchers' analytical approach could be refined to directly reveal the voltage variability (and power quality impact) at specific customer sites due to any given network measures, and to assess the extent to which a given measure expands opportunities to implement CVR.

The NYSERDA PQ event distribution and the ITI PQ event threshold curve identified by NCI offer the possibility of a much more refined approach to power quality impacts of network measures that could be explored. It would be possible using the Energynet® model to assess average delivered voltage and voltage "sag" under peak conditions at each individual location serving a commercial or industrial load. The voltage impact and accompanying power quality on this population of locations of any given network performance improvement measure could be directly evaluated through simulations; moreover, measures could conceivably be developed specifically for their ability to address voltage deviations at these locations.

The example of a CVR implementation that the researchers provided suggests that the potential for energy consumption reduction from CVR might be many times what NCI estimated, and this potential may warrant much more serious attention. Further, contribution to CVR and power quality are clearly different and arguably additive benefits for network performance enhancement measures that support both. There is apparent tension between the two benefits; where power quality is improved with higher average delivery voltage to the customer (keeping a greater share of minor voltage deviation events within equipment tolerance bands), CVR relies on reduced average delivery voltage. In the researchers' view, both power quality and CVR as defined here are enabled through the remediation of low-voltage buses and flatter circuit voltage profiles. The combination of power quality improvement and expanded CVR potential could greatly elevate the prominence of closer voltage management practices within the distribution system.

This project's results suggest that power quality is a relatively large value component (albeit a customer value), and that importance of CVR could be much higher than the values the researchers used in this study. It is conceivable that for a power system with basic load relief requirements met, the voltage impacts of network measures and their influence on power quality and the ability to implement CVR could be dominant planning drivers.

This study's results show a wide disparity among candidate measures in terms of their impact on reliability. This is a result of, and made possible by, a highly granular reliability assessment approach that distinguishes among different circuits within the subject system. This approach suggests that measures that can expand post-contingency load transfer opportunities for circuits that are otherwise constrained have the most impact.

Perhaps more importantly, these results show that distributed energy resources in specific locations can yield sufficient value through reliability benefits to make a meaningful contribution to their cost.

These results also suggest that distributed energy resources' impact on reliability directly through reduced loading and their ability to defer T&D capital projects are relatively minor sources of value. In fact, in an objective evaluation of the load relief potential of both DER projects and capital upgrades proposed for the subject system, the researchers found only one instance where DER could provide the needed load relief. This is potentially important as overload reduction and T&D capital deferral figure so prominently in many studies on DER benefits.

These results show significant potential benefits from operational changes such as optimization of controls and alternative topologies. This conclusion supports the use of advanced analytics that can reveal these opportunities and assist in their implementation. It also at least suggests the need to examine utility financial incentives to adopt newly developed, initially risky approaches that also do not add to rate base.

The emergence of locational energy pricing in California presents an opportunity to price congestion more transparently and, in turn, price the incremental value of energy sourced within the load center from DER. The two congestion relief values proposed, $15-20/MWh by TIAX and $1.00/MWh or less by NCI, illustrate the need for a better understanding of the economic value of congestion relief.

These results reiterate the researchers' findings in the SVP project that there are significant potential benefits from distributed energy resources, but that these benefits are related to specific resources in specific locations and having specific operational characteristics. To realize these benefits there is a clear need to refine methods and incentives to reflect real differences in the merits of projects within a utility service area, nodal pricing zone, ZIP code, circuit, or even on the same street.

4.1.4. Network Monitoring

In this project the researchers demonstrated the use of the Energynet® model to identify gaps in existing system condition monitoring in the Hobby system relative to the researchers' monitoring density specification, obtaining and implementing augmenting monitoring, and integrating this set of monitors together within SCE's legacy communication and data management systems. The researchers also obtained real-world experience in implementing a wide-area system condition monitoring system making heavy use of legacy instrumentation, integrating new instrumentation with legacy communications systems and data management systems, and integrating this wide-area monitoring with a high-definition system model. This is relevant to deployments of this type that might support Wide Area Situational Awareness applications in a future "smart grid." This is further discussed below.

Monitoring Density

The "monitoring density" specification the researchers established for this project was

- Current and MVAR or power factor for every circuit.
- Voltage profile for every circuit.

The researchers found this monitoring density sufficient to permit them to "calibrate" the transformer tap settings in the Energynet® simulation with those in the field, and by doing so make reasonable comparisons of simulated power flow with field power flow readings for each circuit at its source. This is sufficient to conclude that the necessary assumptions and infill incorporated in the Energynet® simulation are close enough to yield simulated system conditions that are usefully similar to those experienced (or at least measured) in the field. Further, based on the researchers' experience, the absence of multiple voltage reads in most circuits, voltage reads at or near the substation bus, or power factor as well as current on most circuits would reduce or eliminate the researchers' ability to perform such a calibration.

A related question is whether this monitoring density is adequate to support Wide Area Situational Awareness applications. Instrumentation alone, at this level of density, would fall far short of a general ability to detect any low voltage areas or optimize power flows. However, a detailed system simulation that has been validated with the instrumentation at many, widespread monitoring points offers the confidence that system conditions at un-monitored points are reasonably well characterized. In other words, with a good simulation it is not necessary to monitor every point in a system. Such a simulation and related analytics, in turn, support the ability to evaluate the power system's power flow and performance under contingency conditions. With all of these elements in place, the monitoring density achieved in this project would approach adequacy to support automated management systems.

The most obvious shortcomings with the monitoring density applied here are the general inability to confirm power flow distribution on individual legs of Y-shaped circuits and the inability to confirm voltage levels off the 3-phase mains, at the point of connection to most customer service transformers. The researchers believe the former could be addressed on a case-by-case basis. A reliable high-definition model of the system could be used to identify areas where more granular power flow instrumentation is expected to be meaningful.

The latter is a more difficult problem. Conditions on one lateral may not shed much light on the conditions on another lateral, thus strategic monitoring may not be achievable. Enabling voltage reads on a small but well-distributed share of customer meters through an Automated Metering Infrastructure (AMI) deployment and integrating those data in a distribution monitoring system are, in the researchers' view, the most practical way to "see" voltage levels on the system laterals. The researchers do not believe, however, that continuous voltage or consumption data from customer meters alone – that is, without circuit-level monitoring and a topologically complete, validated systemwide simulation – is adequate to support Wide Area Situational Awareness applications.

Monitoring Alternatives

Monitoring capability within distribution system reclosers, capacitor controls, and other devices appears to be a common feature, and going forward the presence of such capability in devices actually deployed by network operators may be the norm. However, single-purpose distribution monitoring devices, particularly the readily available, low-cost, easy-to-install variety that would be ideal for augmenting existing monitoring to achieve a given monitoring density, appear to be much less available.

The researchers found satisfactory monitoring solutions for this project, but they all involved adaptations of existing products; these become possible solutions for future deployments. The researchers identified and described a few potential alternatives to the devices used, but they all had some drawbacks at least for this application. There are vendors who appear to have the ability to introduce additional products that would be suited to standalone distribution monitoring. Possibly the market for this class of standalone monitoring devices is not crowded because the case for extensive distribution system monitoring for its own sake has yet to be made. Perhaps the timeliest conclusion is that AMI deployments represent an opportunity to introduce a large number of new distribution system condition monitoring points, and specifying communicating AMI meters with voltage and power factor measurement should be a prominent element in these initiatives.

Wide-Area Monitoring Combining Legacy and New Equipment

In this project the researchers demonstrated the development of a pervasive network monitoring system monitoring capable of supporting Wide Area Situational Awareness applications thorough the integration of monitoring data streams from existing distribution devices, augmentation of system monitoring at strategic points, and mapping the field reads to a systemwide model with enough detail to characterize each individual system node. The scale of this deployment is significant. In Section 3.4 the researchers provided a comparison of this project with two other well-publicized “smart grid” deployments. The key observation is that the scale of this project is 5 to 10 times the size of the “Smart Grid City” project. The Hobby project was also operational as of late 2009. The Hobby project does not include the AMI element but even considering that the cost difference compared to the others is striking.

The Hobby project is distinguished by its intensive use of legacy equipment; the researchers achieved this level of pervasive monitoring by adding to the stock of monitoring devices in the Hobby system by less than 10%. The researchers feel making maximum use of any “legacy” instrumentation must be the starting point for any wide-area system monitoring deployment.

In this case the integration of the added monitoring devices, both the collection of their data remotely and the handling of their data once collected, was achieved seamlessly, within the legacy systems without modification. The largest challenges were local – finding sites for instruments and providing instrument power.

This seems to be a clear demonstration of the practicality of leveraging existing assets to achieve distribution system monitoring capable of supporting advanced smart grid applications.

4.1.5. Operational and Planning Applications

In this project, the researchers successfully demonstrated the automated transfer of key data sources and accomplishing system data updates of the Energynet® model with a turnaround time that would allow operators to evaluate operational issues with a current model. The researchers confirmed that the Energynet® model changes as expected as system conditions change.

The researchers' efforts in this project were intended only to demonstrate the basic suitability of the Energynet® model for operational purposes, whose uses are not yet well identified. The researchers believe a validated power delivery system simulator that is continuously updated to reflect current system conditions is a new enough idea that it will take time for the most important uses to evolve. Maintaining this system so it is place during a period when extraordinary operating conditions generate extraordinary system data would be ideal.

4.1.6. Verification of Methodology

The results of this project indicate that the Energynet® model provides a statistically valid representation of actual field conditions, when considering real power flow, MVA flow, current flow, and the most demanding, voltage. The points of comparison for this assessment are numerous and highly dispersed within the subject system, capturing the variability of conditions within the system. These results also show that the closeness of the simulation holds as underlying system conditions change. Thus, the researchers conclude that the Energynet® simulation is validated with field results.

In this project, the availability of reactive power measurements alongside current measurements and widely dispersed, pervasive voltage measurements proved critical. Validating a very detailed model requires very granular field data; however, these system sensors provide valuable insight into system conditions on their own, as a standalone benefit.

The results achieved here provide a simulation of system conditions that is easily granular enough to reveal a circuit voltage sag of greater than 10%. It may even be close enough to identify, for example, an individual capacitor modeled "on" based on system data, but likely not operating properly as shown by a difference between simulated and field-read voltages at the capacitor's location.

One of the real potential values of the Energynet® model is the ability to predict system conditions reliably in areas without instrumentation. A necessary first step, completed here, is to reliably predict system conditions where there are instruments to provide verification.

4.2. Commercialization Potential

The project's objectives speak to the usefulness of the Energynet® method to decision-makers, though the project scope does not address its actual availability for use. Nonetheless, two project objectives, demonstration of the practicality of the Energynet® method and demonstration of the potential to support operational decision-making, impacted the commercialization potential of the Energynet® method. In the SVP Project the methodology was implemented by hand, essentially to support one-time studies. During the course of this project, the steps in developing an Energynet® model were hardened and increasingly automated to support these two objectives. Source data retrieval from the utility was also increasingly automated with appropriate data security provisions. With adequate resources the Energynet® method could evolve to a simulation platform that, once implemented for a utility system, can be continuously maintained and presented to the utility as a secure Web application. This platform could support various "applications," initially providing analytical results related to those presented here. In each case the applications would utilize the systemwide scope and distribution-element detail of the Energynet® model, as well as the ability to incorporate and reflect ongoing changes to the utility's system and as-measured feeds of sensor and device status for the subject system. As employed in this project, the model is in a standard format that can interoperate with commonly used power system analytical tools, and can support applications that use those tools.

4.3. Additional uses for Energynet®

The results of this project and the SVP Project clearly indicate vast differences in the grid benefits of distributed generation depending on location. This methodology could be applied to the development of locational "feed-in tariffs" that would both direct existing distributed generation financial incentives to those projects that benefit the grid, and help to direct project developers to beneficial locations without revealing sensitive details about the grid. While customers in some locations would be eligible for greater incentives than those in others, through this methodology there is a solid objective basis for those differences. These tools could also be applied to assess the systemwide impacts of high penetrations of renewable resources, in particular their impacts on system loading and voltage variability, both within the circuits where such projects are located and in the system as a whole.

The Energynet® method could become a key element in the development of smart grid "roadmaps." In this project this methodology is demonstrated for objectively assessing a wide variety of network enhancement measures against a comprehensive set of benefit categories. As utility and policy decision makers arrive at a consensus on what a smart grid should do, this methodology can be used to evaluate individual smart grid initiatives for their direct, demonstrated contribution to agreed-upon smart grid objectives and to compare different options. These analyses would support thorough, objective project justifications for smart grid projects, putting to rest questions of whether the benefits of favored smart grid initiatives outweigh their costs.

Distributed storage projects were included as candidate DER projects for the Optimal DER Portfolios developed for this power system, but using a fairly simplistic approach. Nonetheless, an important finding in this project is that the size and location of storage impacts the grid benefits it provides on peak and its grid impacts off peak, which in turn are non-trivial. This methodology would permit a comprehensive evaluation of distributed storage, ranging from substation to community to household sizes against full set of benefit categories. Such an analysis might well reveal important differences in the merits of storage technologies and strategies under consideration.

As indicated, the results presented here for the benefits of CVR may be greatly understated. A sustained 1-2% reduction in peak period energy consumption over a significant share of the Hobby system due to slightly reduced service voltage would provide very substantial cost savings and attendant environmental benefits. The Energynet® model of the Hobby system with integrated field instrumentation represents a test bed that could be used to identify areas where voltage could be reduced immediately while remaining well within delivery specifications, and for testing through simulation transformer tap and capacitor management schemes to flatten and reduce circuit voltage profiles, thereby extending the safe applicability of CVR. Such a project would provide real-world experience regarding the true potential of CVR.

The potential to use the high-definition system model to support operational decision-making emerged during the course of the project. One of the project outcomes was a successful demonstration of the ability to deliver new source data automatically and to refresh the model rapidly enough to accommodate the ongoing changes to the underlying system. However, the potential operational uses of this tool were not fully explored. The researchers believe this model could be used with ongoing updates as a system state estimator, and could support operational purposes such as "dry runs" of operational evolutions or "replay" of conditions immediately preceding a system outage.

The researchers demonstrated in this project an approach that quantifies the change in expected unserved energy (i.e., the reliability impact) attributable to an individual network enhancement measure based on its impact on the system's inherent vulnerability to random contingencies. This approach does permit a direct quantification of the reliability impact of an individual measure, one of the goals of the project. However, this approach would be improved if the system's inherent vulnerability to random contingencies and the factors contributing to that vulnerability were validated through studies of historical and ongoing actual system outage experience.

All of the analyses presented in this report are based on static results, or snapshots of system conditions. The presentation of a time series of static results provides a quasi-dynamic view of a system, and the researchers believe such studies would provide additional insights into some system phenomena. The researchers also believe these tools could be adapted to dynamic analysis provided there are adequate dynamic models of system elements available. Dynamic analysis within this methodology could reveal the device, circuit, and area-wide benefits of different types of storage technologies other advanced grid management devices.

4.4. Benefits for California

The results of this project demonstrate an advanced power system simulation tool providing unprecedented visibility into the power delivery system. These results demonstrate the use of the methodology to identify weak areas of a power system in terms of reliability, loading, voltage, power quality, and losses. This project further demonstrates assessment of a wide variety of network measures for their demonstrable and cost-effective ability to address these issues and improve network performance, and to directly compare such measures in engineering and economic terms. The use of such a tool could support strong project justifications, promoting the deployment of demonstrably more effective measures at lower cost to improve power grid efficiency, reliability, power quality, and operating costs, benefitting California's utilities, their customers, and the environment.

A key motivator in the formation of this project was the ability to objectively compare non-traditional non-wires and DER measures to improve system performance with traditional network expansion projects, in the hope that non-wires and DER measures would become more widely adopted where appropriate. Now this objective has evolved to the ability to accommodate high penetrations of intermittent distributed generation as well as distributed storage and plug-in vehicles. Each demands the ability to "see" the network at the level where these elements are connected while also "seeing" their impacts on the entire system. A practical, validated power system simulation with systemwide scope and distribution element-level detail should readily permit California's utilities to accommodate these resources while minimizing risk to the power system and unnecessary cost burdens on customers

The most immediate employment of these capabilities may be in the area of "smart grid" initiatives which may run into the billions of dollars, all of which will be funded by utility customers. Once the objectives of these initiatives are defined, the analytical tools and approaches demonstrated in this project would support deployment of those operational and system measures demonstrated to yield the greatest value relative to established objectives at the least cost, supported by the results of detailed evaluation and little guesswork.

Glossary

AC	Alternating current
GRIDfast™	GRIDiant Corporation's Power System Optimization and Analysis Software
AMI	Automated Metering Infrastructure
California ISO	California Independent System Operator
CEII	Critical Energy Infrastructure Information
CERTS	Consortium for Electric Reliability Technology Solutions
CIM	Common Information Model for power network data exchange
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CVMI	Current and voltage monitoring insulator
CVR	Conservation voltage reduction
DCMS	Distribution control and management system
DER	Distributed energy resource
DG	Distributed generation
DNP3.0	Distributed Network Protocol
DR	Demand response
E3	Energy and Environmental Economics, Inc.
Energy Commission	California Energy Commission
ETL	Extraction, transformation and loading
EPRI	Electric Power Research Institute
GPRS	General Packet Radio Service
HVAC	Heating, ventilation and air conditioning
IEPR	Integrated Energy Policy Report
IOU	Investor-owned utilities
ITI	Information Technology Industry
kV	Kilovolt
KVAR	Kilo Volt Amp Reactive
kW	Kilowatt
kWh	Kilowatt-hours
kWh/yr	Kilowatt-hours per year
LBNL	Lawrence Berkeley National Laboratory
GRIDfast™ LF	The load flow component of GRIDfast™
LMP	Locational marginal price

MVA	MegaVolt Amps
MVAR	Mega Volt Amp Reactive
MW	Megawatt
MWh	Megawatt-hours
MWh/yr	Megawatt-hours per year
N-1	With the loss of the largest single component
NCI	Navigant Consulting, Inc.
NOx	Nitrogen oxides
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
P-Index	Real Power Resource Sensitivity Index as determined by GRIDfast™
PIER	Public Interest Energy Research
PQ	Power quality
PSLF	GE Energy's Positive Sequence Load Flow power flow program
P.T.	Pole top transformer
PU	Per-unit (Voltage)
PV	Photovoltaic
Q-Index	Reactive Power Resource Sensitivity Index as determined by
RD&D	Research, development, and demonstration
RPS	Renewables Portfolio Standard
RSI	Resource Sensitivity Indices as determined by GRIDfast™
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SGIP	Small Generation Incentive Program
SOx	Sulfur oxides
SVP	Silicon Valley Power
T&D	Transmission and distribution
TCUL	Tap Changer Under Load
U.S. DOE	United States Department of Energy
V2G	Vehicle to grid
VAR	Volt Amp Reactive
VOS	Value of service
VRB	Vanadium redox battery
WASA	Wide Area Situational Awareness

WiMAX	Worldwide Interoperability for Microwave Access
WECC	Western Electricity Coordinating Council